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BRINE DISPOSAL TREATMENT PRACTICES RELATING TO THE OIL PRODUCTION INDUSTRY

George W. Reid, et al

Oklahoma University

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ABSTRACT

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This report was submitted in fulfillment of Project No. 14020 FVW, Contract No. 14-12-873, by the University of Oklahoma Research Institute under the sponsorship of the Environmental Protection Agency.

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SECTION I

INTRODUCTION

As an average, 2-3 barrels of brine are produced per barrel of oil (the actual range may be negligible volumes to over 100 bbl/bbl oil). This represents 20-30 million bbl/day brine production in the United States. While there have been rare instances of potable oilfield brines, most are highly saline. The major salts contributing to brine salinity are the sulfates (SO_4^{-2}), bicarbonates (HCO_3^{-1}), and chlorides (Cl^{-1}) of the cations sodium (Na^{+}), calcium (Ca^{+2}), and magnesium (Mg^{+2}). The concentrations of these and other constituents normally found in oilfield brine are compared to those of seawater in Table 1.

Table 1. COMPARISON OF SEAWATER AND OILFIELD BRINE[1-3]

	Seawater (mg/l)	Oilfield Brine (mg/l)
Na^{+1}	10,600	12,000-150,000
K^{+1}	400	30- 4,000
Ca^{+2}	400	1,000-120,000
Mg^{+2}	1,300	500- 25,000
Cl^{-1}	19,000	20,000-250,000
Br^{-1}	65	50- 5,000
I^{-1}	0.05	1- 300
HCO_3^{-1}	?	0- 1,200
SO_4^{-2}	2,700	0- 3,600

As an indication of the important domestic geographic areas, state oil production and tax figures are presented in Table 2.

The two basic types of oil producers are the majors (often diversified conglomerates) and the independents. Generally, the majors are integrated corporations having multibillion-dollar assets. They tend to engage in all aspects of petroleum operations: exploration, production, transportation, refining, and distribution. Operations cover offshore and onshore drilling on a worldwide scale. Chase Manhattan Bank lists a group of 27 major oil corporations whose 1969 operations accounted for approximately 70% of all the crude oil produced in the United States and nearly 60% of the total output of the rest of the world.[4, 5]

The second type of oil operations involves the activities of thousands of independent oil companies. As a general rule these companies operate in the North American Continent--mainly in the United States. With regard to economic size and operation, independents tend to be much smaller than majors. Operations are directed almost exclusively to exploration and production. While independents produce a substantial quantity of the oil used in the United States, perhaps their largest contribution is in the field of exploration. Approximately 85% of the domestic exploratory wells completed in the United States are drilled by the independents.[6] The independents often resort to financial arrangements such as promotional speculation, in which a package operation is funded by speculators. In exchange for providing a portion of the expenses, a driller may trade a percentage of the profit, such as 25% of the strike. Published information reveals that approximately 70% of the operator risk capital is obtained from outside investors.[6]

Much of the activity of the independent producers is termed stripper well operation, meaning that the maximum output per well is ≤ 10 barrels per day (special legislation which restricts production to this level is an exception to the definition).[7] In 1969 there were a total of 358,000 stripper wells which produced 454 million barrels of crude oil (an average of 3.5 barrels per well per day).[7]

Table 2. STATE CRUDE PRODUCTION AND TAXATION
(1967 or 1968 Statistics)

State[a]	Crude[b] M. bbl	Prod. tax[c] %	Pet. tax[d] %	Amt. pet. state tax[e] $M
Alabama	7.3	.4	21	100.0
Alaska	74.1	6.3	56	33.9
Arizona	2.4	0	--	--
Arkansas	21.1	.8	23	66.1
California	460.9	4.6	17	798.8
Colorado	31.9	.4	16	54.5
Florida	1.6	1.9	18	194.0
Illinois	56.4	0	16	275.2
Indiana	10.1	.2	19	144.0
Kansas	94.5	.2	15	55.2
Kentucky	15.5	0	19	86.9
Louisiana	817.4	33.8	51	355.3
Maryland	.2	0	14	90.5
Michigan	13.7	.4	16	237.8
Mississippi	58.7	3.0	28	90.4
Missouri	0	0	16	97.5
Montana	48.5	2.3	26	27.2
Nebraska	13.4	.5	38	52.1
Nevada	.2	0	--	--
New Mexico	128.6	5.3	28	60.8
New York	2.0	0	7	300.0
N. Dakota	25.0	3.4	19	19.3
Ohio	9.9	0	24	274.0
Oklahoma	223.6	10.2	29	126.6
Pennsylvania	4.4	0	16	287.5
S. Dakota	.2	0	23	18.8
Tennessee	0	0	24	122.4
Texas	1133.4	18.8	40	513.5
Utah	23.5	.7	16	29.7
Virginia	0	0	19	123.5
W. Virginia	3.6	1.0	17	46.5
Wyoming	144.2	.2	21	14.3

[a] State
[b] Production crude oil, annual (million barrels)
[c] % state revenue consisting of total petroleum production tax
[d] % state revenue consisting of total petroleum tax
[e] Amount total petroleum state tax (million dollars)

The combined services of the majors and independents currently supply approximately 75% of the total energy requirements of the United States.[8]

Considering the modes and areas of operation of the majors and independents, a rather interesting configuration seems to be inferred linking production with demand. The majors, by definition, supply petroleum products to their consumers in usable form via the refining and distribution functions they perform. These companies bring the crude oil from production sites to the refineries by pipelines, trucks, railcars, ocean tankers, or a blend of these transport vehicles. However, approximately 15% of American oil production comes from production sites of the independents in the 32 oil-producing states, and roughly 85% of the total exploratory drilling is done by independents. Combining these figures implies that (assuming a successful well is equally likely for an independent as for a major) much of the supply of American production results from the initial exploratory efforts of the independents.

The implication is that, while almost all the oil used in the United States has been processed by at least one of the majors, of the 80% produced domestically, 15% has come from independent production, and 85% of the burden for discovering the remaining domestic production has come from the exploratory efforts of the independents. Further, if it is recognized that oil in place has no more value than gold or uranium in place--which is zero in reality--then the contribution of the independent is not quite so overwhelmed by the activities of the majors.

SECTION II

BRINE POLLUTION

STATE AND FEDERAL REGULATIONS

Prior to 1935, indiscriminant discharge of oilfield brine was common practice. Thereafter, federal and state legislation and policy impacted brine disposal. In general, oil-producing states regulate brine disposal activities within their respective borders. The U.S. Environmental Protection Agency (EPA) can, under certain conditions, instigate civil action in the event of brine pollution.

A listing of state agencies responsible for regulating oil and gas is found in Appendix A. The information was gathered through correspondence with each of the 50 states from January to June, 1971. Entries have been divided into five categories for each state: state oil regulatory agency; publication of regulations (most recent title and date); other state agencies assisting in oil production and brine disposal; published allowable disposal methods; and disposal permit costs. Because of reoccurring changes in state and federal legislation, operators who are contemplating brine disposal would be well advised to obtain current revisions to state regulations, EPA's policy on subsurface disposal, and the Federal Water Pollution Control Act.[9]

EFFECTS OF SALINITY

The high salinity of most oilfield brines, as measured by total dissolved solids, is caused by soluble salts. The major species have been listed in Table 1. Some of these inorganic ions have adverse effects on animal and plant life. Upper limits for human drinking water established by the USPHS are chloride (250 mg/l Cl), sulfate (250 mg/l SO_4), and total dissolved solids (500 mg/l).[10] In the case of some brines, 1 barrel could cause over 700 barrels of fresh water to exceed the USPHS chloride limit.[3] The taste threshold of sodium chloride is about 500 mg/l Cl, meaning that a salt taste was identified at this concentration and higher (actual range for individuals is 120-1200 mg/l Cl).[10] Magnesium concentrations in excess of 125 mg/l Mg can exert on humans a laxative effect. Livestock tolerances to brine depend upon the concentration and composition of the salinity and the availability of alternative sources of fresh water. For adult animals, the upper safe limits for salinity composed mostly of NaCl are presented in Table 3.[11]

Table 3. SALINE WATER TOLERANCES

Species	Total Soluble Salts (mg/l)
Poultry	2,860
Swine	4,300
Horses	6,500
Cattle	10,000
Sheep	13,000

EFFECTS OF NONIONIC COMPONENTS

In addition to salinity, certain nonionic materials are common to oilfield brines, such as oil, dissolved organics, and dissolved gases. Some of these are toxic, and others are detrimental to surface water resources. For example, oil may interfere with the transfer of oxygen from the atmosphere into the water (essential for fish life), coat birds and fish, impart an objectionable taste to fish, exert a direct toxic action on some organisms, or interfere with the fishfood organisms in the natural food cycle. Oil can adsorb onto clay particles, settle to the bottom, and remain as a continuing source of pollution. Fish can suffer from depletion of dissolved oxygen brought about by chemical oxidation of dissolved gases such as hydrogen sulfide or biological oxidation of petroleum products.

Some testing has been performed with oils to determine general toxicity levels. These levels vary according to the species involved, and the conditions of exposure, but, in general, aromatics are the most toxic of the usual oil constituents, Naphthenes and olefins are intermediate in toxicity, and straight paraffins are the least toxic. Within the above general groups, the low-boiling aromatics and the smaller molecular constituents are the most toxic.[12]

It is difficult to gauge the pollutional significance of the oil which accompanies a brine released to surface water. Oilfield wastewaters contain as much as 0.1-0.33% oil by volume.[12] Although dissolved gases and components of the oil are potentially hazardous, these substances tend to dissipate before they accumulate and reach toxic levels. Should oil accumulate to a concentration of 3-5 mg/l, freshwater fish which are especially sensitive to oil components may begin to experience toxic effects.[13] In 1963, petroleum operations accounted for 44% of the fish killed by industrial pollution and 14% of the fish killed by industrial/municipal pollution.[14]

SECTION III

BRINE DISPOSAL

CONSIDERATIONS IN SELECTING METHODS

Once-common brine disposal practices which are now illegal include indiscriminant surface discharge, controlled release to streams at high flow, and impoundment in unlined evaporation/seepage pits. These early methods have resulted in pollution of surface and groundwaters through salt seepage and surface scarring over large land areas.

Selection of a disposal method depends on several considerations, beginning with the legal specifications set forth by the state regulatory agency (see Appendix A). In most states, the operator must apply for a disposal permit (at no cost or a small fee) prior to initiating brine disposal. The application provides for a statement by the regulatory agency as to suitability, legality, size, and location of the proposed disposal method. In this way, the state maintains up-to-date records on disposal operations and is assured a margin of safety with protection of fresh water resources.

State disposal records are available to operators and contain extensive information on the location, size, and type of geologic formations encountered at each well location. The legal responsibility for developing, operating, and abandoning a disposal operation rests with the individual operator, who must be familiar with current state revisions on the subject.

The operator must then choose among the several disposal methods permitted by the state. Site conditions are important considerations: soil types, geology and hydrology, formation characteristics, and well penetrations in the vicinity. For example, abandoned, improperly-plugged wells represent avenues of brine movement from the receiving formation to freshwater aquifers and even surface water.

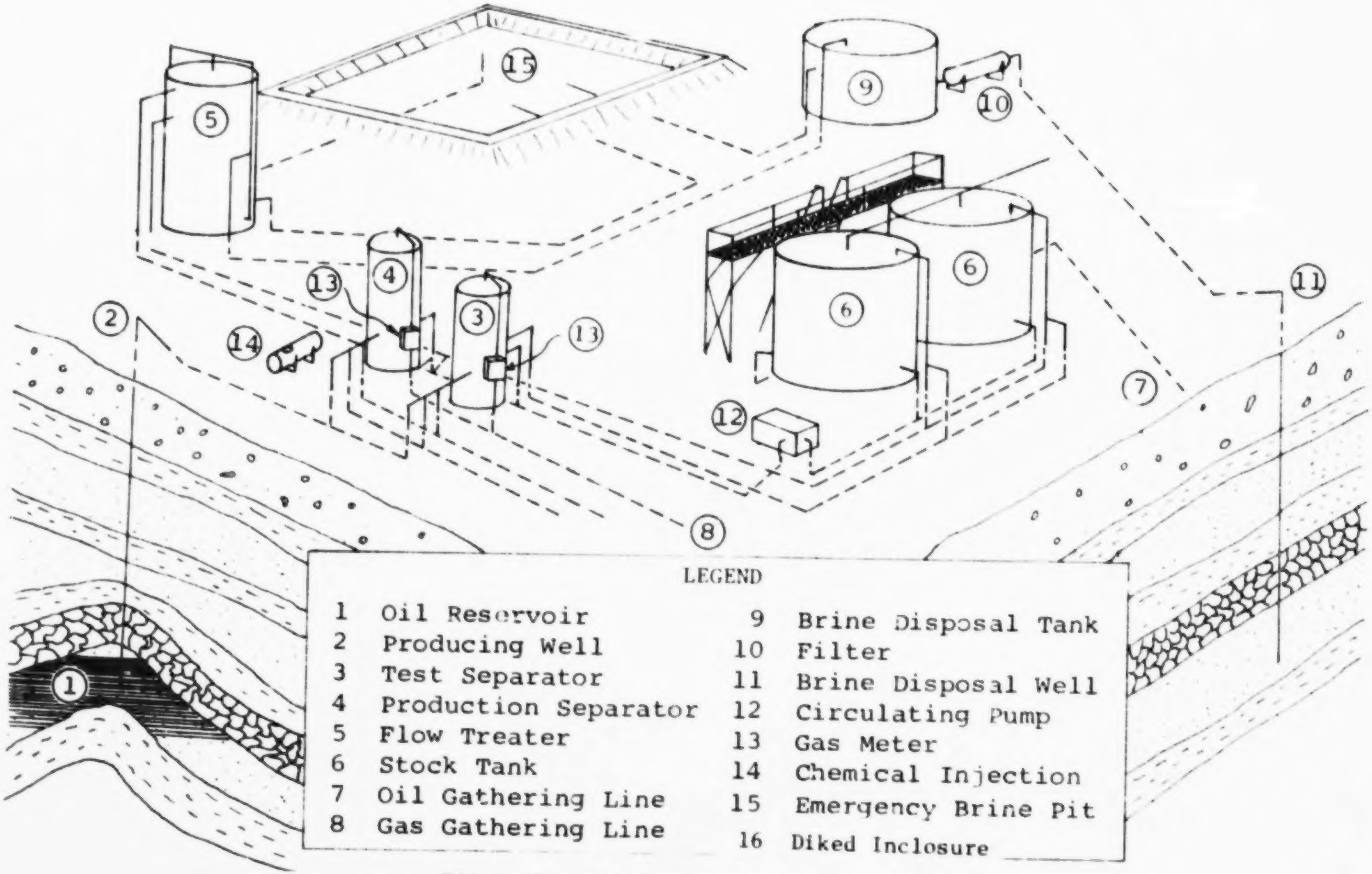
Economic considerations are then superimposed. The operator must adopt a plan at the initial stage of reservoir development which will effectively deal with an initially high rate of oil production, gradually decreasing, and an initially low rate of brine production, gradually increasing. This decision may involve a multimillion dollar combined operation lasting in excess of 30 years.

GATHERING SYSTEM

The production/disposal system is illustrated in Figure 1. The flowlines and related equipment originating at the oil separator constitute the beginning of the disposal process.

Three modes of gathering systems are possible: by gravity, by pressure, or via a combination of the two. A gravity gathering system uses no pumps, and flowlines conform to the natural drainage patterns of the land. The pressure system does not require as extensive a topographic survey because pumps supply the main driving force. Probably the most logical design would be a combination of the two systems, taking advantage of natural drainage as well as reducing the number of flowlines where topography is unfavorable.

The gathering system should be designed and equipped not only to withstand the corrosive characteristics of brine but also to alleviate potential scaling which, along with oil, is most likely to accumulate in the high points. Where arches are unavoidable, vents should be used. These can be constructed from a tee in the line with a riser above the hydraulic gradient.[15]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LEGEND
1 Oil Reservoir
2 Producing Well
3 Test Separator
4 Production Separator
5 Flow Treater
6 Stock Tank
7 Oil Gathering Line
8 Gas Gathering Line
9 Brine Disposal Tank
10 Filter
11 Brine Disposal Well
12 Circulating Pump
13 Gas Meter
14 Chemical Injection
15 Emergency Brine Pit
16 Diked Inclosure

Figure 1. Oil Production-Disposal Scheme.

Pipe Sizing

Maximum expected flow rates, available head, and head loss due to friction are criteria from which pipe sizing is determined. Future brine production must be carefully estimated since an increase in line capacity is difficult to obtain.

Materials

The choice in materials for saltwater piping depends on the operating pressure and temperature, the corrosive characteristics of the brine, the life of the system, and the relative costs involved. In most systems corrosion is the predominant criteria. Table 4 shows the type and service conditions of pipe used in saltwater gathering systems of the East Texas Salt Water Disposal Company. Savings in time and labor are possible where plastic pipe can be used. An example is a 12-mile installation of 3- and 4-inch polypropylene pipeline in the Person-Panna Maria field in Texas.[16] The line was completed in 11 days by a three-man crew and heat-fusion was used to weld the joints in less than 1-1/2 minutes each.

The East Texas Salt Water Disposal Company has had experience in the use of several different types of pipe, including asbestos-cement-lined, cast iron, and plastic.[17] The cast iron pipe was lined with a special Portland Cement mix and seal-coated on the exterior with coal tar. Asbestos-cement was used almost exclusively, but cast iron was preferred for lines requiring an excess of 200 psi. The asbestos-cement pipe was resistant to brine corrosion but was rather fragile and required considerable care in installation. The cement-lined pipe had the disadvantages of large variances in the internal diameter and the possibility of damaging the lining, particularly while coupling the joints.

Scale Removal

At regular time intervals, scale removal from the internal surfaces of pipe is required. The most common method is to flow a "scraper" or

Table 4. PUBLISHED DATA ON PIPE GENERALLY USED IN SALT WATER GATHERING SYSTEM SERVICE[17]

Type of Pipe	Nominal Size, Inches	Working Pressure, Psi Rated at 80° F	Working Pressure, Psi Rated at 150° F	Applicable Service
Steel				
Schedule 40				
Grade A	2-12 incl.		1,900-910	Noncorrosive
Continuous-weld and lap-weld	2-12 incl.	750- 490	750-490	Noncorrosive
Cement-lined	2-12 incl.	750- 490	750-490	Corrosive
Plastic-lined	2-12 incl.	750- 490	750-490	Corrosive
Asbestos Cement				
Class 100	3-12 incl.	100	100	Corrosive
Class 150	3-12 incl.	150	150	Corrosive
Class 200	3-12 incl.	200	200	Corrosive
150-ft. head	3- 8 incl.	65	65	Corrosive
Plastic				
Butyrate	2	102	20	Corrosive
Butyrate	3	73	11	Corrosive
Butyrate	4	70	11	Corrosive
Vinyl	2	133	44	Corrosive
Vinyl	3	103	32	Corrosive
Vinyl	4	98	29	Corrosive
Fiber-reinforced epoxy	2	500-1,000	360-775	Corrosive
Fiber-reinforced epoxy	3	350-1,000	270-775	Corrosive
Fiber-reinforced epoxy	4	200- 500	150-360	Corrosive

"pig" through the line, introducing and removing it at scraper traps. Types vary, but the most common are the steel-ball, chained rubber ball, cementing plug with trailing wire-brush, go-devil with lead-end knives and cutter wheels, and the spiralbrush.[18] Scraper traps are placed at strategic locations, such as the connection to a tank battery or a point of line size change. Care must be taken to prevent spilling brine when opening a trap. In cases where scrapers are not effective, it becomes necessary to either acidize the line or dismantle it and mechanically remove the scale. Acid has the disadvantage of attacking steel, cement-lined, and asbestos-cement pipe.

Pumps

Because they can handle relatively large volumes of fluid at low pressures, centrifugal pumps are used extensively in saltwater gathering systems. They are easily adaptable to electric motors, easily maintained, and can operate under a shut-in head if necessary. Experience obtained in the East Texas oilfield has indicated that attention to suction conditions is one of the most critical considerations of design. Inadequate filling of the suction can seriously erode or cause cavitation of an impeller in a matter of days. Flooded suctions have been found to pay for the increased costs of installation by savings in maintenance cost. The suction line should be a straight run and as short as possible, with the line size at least twice that of the pump suction inlet.

Corrosion-resistant pump parts are also a critical consideration in brine systems. The metallic elements used in pump construction should be closely related in the electromotive series; otherwise corrosion will take place by galvanic action. Two examples of the metal combinations used in a centrifugal pump for brine service are: all-bronze pumps with monel shafts and packing sleeves, and cast-iron cases with aluminum/bronze impellers. Brand name alloys, such as Ampcoloy and Worthite, have also given excellent service.[18]

DIRECT DISCHARGE

In a very limited number of cases the quality of oilfield brine is such that direct utilization or legal discharge to surface water is possible with little or no treatment. Examples can be found in Wyoming and Southern California where the brine is used for irrigation and livestock watering.

For economic reasons, brine discharge to tidewater or to the ocean is limited to operators in relatively close proximity to coastlines. In addition, coastal states such as California are drafting effluent limitations on ocean discharges for many of the common constituents of oilfield brine (e.g., phenolics, suspended solids, metals, ammonia, and extractable oil).[20] Studies of desalinization brines suggest that discharges to shorelines (especially bays and estuaries) could adversely affect the marine environment if circulation patterns either channel harmful materials along coastlines to important marine habitats or hinder the rapid dilution of toxicants necessary to prevent fatality in fish and shellfish.[19]

Because of current controversy over direct discharge, the operator is advised to contact the appropriate state regulatory agency before attempting such a system. Table 5 summarizes the advantages and disadvantages of direct discharge disposal.

EVAPORATION PONDS

The evaporation pond or pit is a surface handling mechanism which, when properly constructed and operated, relies on the atmosphere to concentrate brine by removal of water vapor. Major producing states are viewing evaporation pits with disfavor because of a history of faulty design and operation. For example, Texas and Oklahoma have outlawed their usage for brine disposal. Ponds improperly constructed are "seepage" pits and result in the formation of pockets of salt in the soil which slowly migrate to groundwater via leaching and percolation and may cause pollution for hundreds of years.[21]

Table 5. SUMMARY OF DIRECT DISCHARGE DISPOSAL

Advantages	Disadvantages
1. May be very inexpensive to build and operate.	1. Impractical for long distance to discharge site or where rough terrain boosts pipeline and pumping costs.
2. May require minimum treatment.	2. Pipeline right-of-way cost may prove overly expensive.
3. Is not restricted by the amount of brine it can handle.	3. Treatment costs for agriculture or cooling use may be prohibitive.
4. Does not require extensive geohydrologic analysis necessary to ascertain suitable disposal aquifer.	4. Ocean discharge pipeline and other equipment requires extensive corrosion protection.
5. May be mixed with other water and diluted to a quality which is acceptable for agricultural and cooling uses.	5. May require regular, extensive chemical testing which can prove expensive.
6. Does not depend on evaporation rate.	6. May require outfall off-shore to protect fish spawning areas.
	7. May require sophisticated and costly pretreatment.

Evaporation Rate

The successful operation of an evaporation pond depends on the annual net evaporation rate of the brine in question for the locality of origin. Values of annual net evaporation rate of fresh water for the United States (Figure 2) are useful only in making relative comparisons of the major geographic areas. Evaporation rate for brine will be significantly lower because of the presence of dissolved solids and oil film. Other variables affect the rate: air and brine temperature, relative humidity, and wind speed. The operator can approximate brine evaporation rate in a specific locale by applying a salt correction to the following expression which describes freshwater evaporation:[22]

$$E = NU\,(e_o - e_a) \qquad (1)$$

where E = evaporation in cm/day.
U = wind speed in miles per hour (mph) measured 2 meters (6.5 feet) above the ground surface.
e_o = vapor pressure in millibars (mb) of saturated air at the brine surface temperature (available from meteorological tables).
e_a = vapor pressure in mb of the air at the 2-meter air temperature (meteorological tables).
N = mass transfer coefficient in cm/(day·mph·mb).

The salt correction is as follows:[22]

	Concentration	Replace e_o by e'_o
At saturation	50,000 mg/l NaCl	$e'_o = .97\ e_o$
	150,000 mg/l NaCl	$e'_o = .91\ e_o$
	300,000 mg/l NaCl	$e'_o = .80\ e_o$

Evaporation of brine within the temperature range 76°-90° F is described by the following multiple regression analysis:[23]

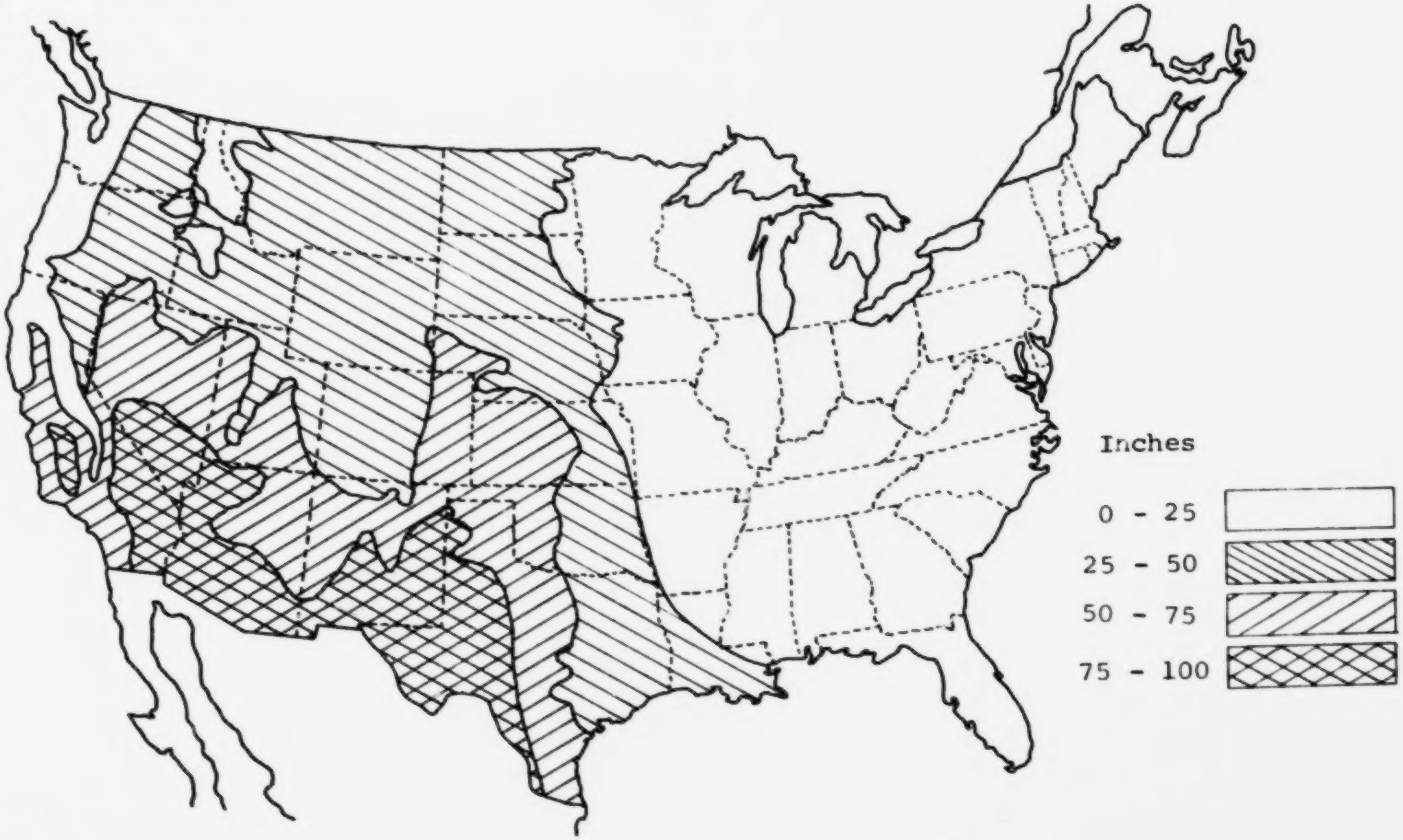

Inches
0 - 25 □
25 - 50 ▨
50 - 75 ▨
75 - 100 ▩

Figure 2. Map of Annual Net Evaporation in Inches[44] (Pan Evaporation Minus Precipitation).

$$E = B_1 (AT) + B_2 (W) + B_3 (RH) + B_4 (C) + B_5 (WT) + B_6 (AT)^{1/2} + B_7 (W)^{1/2} + B_8 (RH)^{1/2} + B_9 (C)^{1/2} + B_{10} (WT)^{1/2} + B_{11} (AT) (W) + B_{12} (AT) (RH) + B_{13} (AT) (C) + B_{14} (AT) (WT) + B_{15} (W) (RH) + B_{16} (W) (C) + B_{17} (W) (WT) + B_{18} (RH) (C) + B_{19} (RH) (WT) + B_{20} (C) (WT) \quad (2)$$

where E = evaporation rate (centimeters per day).
AT = air temperature (degrees Farenheit).
W = wind speed (miles per hour).
RH = relative humidity (percent).
C = concentration of NaCl in increments of 50,000 mg/l NaCl (i.e., for a solution containing 150,000 mg/l, C = 3).
WT = brine temperature (degrees Centigrade) [° C = 5/9 (° F - 32)].

The B values refer to the following coefficients (rounded to the nearest .0001):

$B_1 = -0.2276$
$B_2 = 0.2426$
$B_3 = 0.0874$
$B_4 = 0.2129$
$B_5 = -0.3424$
$B_6 = 1.8153$
$B_7 = 0.2063$
$B_8 = -0.6812$
$B_9 = -0.0781$
$B_{10} = 0.9523$
$B_{11} = -0.0015$
$B_{12} = -0.0003$
$B_{13} = -0.0002$
$B_{14} = 0.0046$
$B_{15} = -0.0019$
$B_{16} = -0.0068$
$B_{17} = 0.0017$
$B_{18} = 0.0001$
$B_{19} = -0.0011$
$B_{20} = -0.0076$

Data using this equation have deomonstrated a high degree of correlation between calculated values and actual measurements of evaporation.[23]

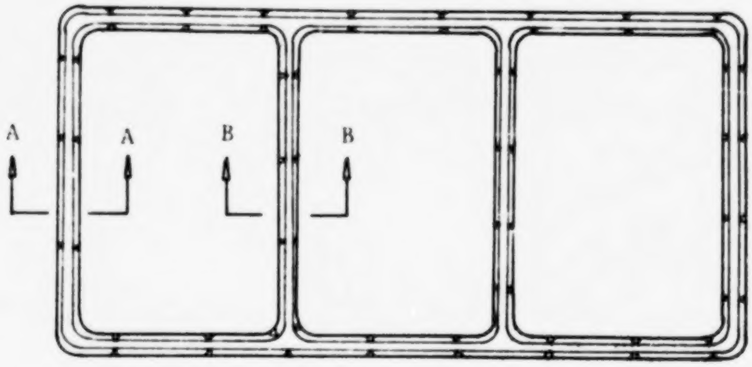
Design Considerations

Design considerations begin with the pond location. This should be close to, but preferably downhill from, the production site to minimize pipelines, rights-of-way, and pumping requirements. A site removed from within well-defined drainage basins will negate the potential pollution from pond failure during heavy runoff. The states which permit evaporation ponds require construction on an impervious stratum or with a lining such as PVC, Hypalon, or Gunite.

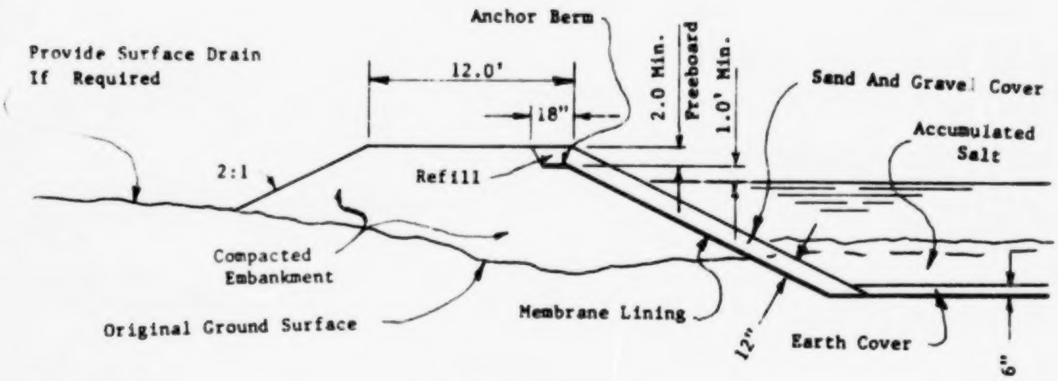
Lining materials must be inert to the organic and acid constituents of brine. Preferably, liners should be tested for reactivity to the brine in question. Flexible liners require a compacted sub-base and soil covering to keep it in place and minimize weathering and puncture (see Figure 3). Underdrains installed at 1 to 2 foot depths beneath the liner (including sides of ponds) are recommended to indirectly describe the integrity of the lining by monitoring the quality of the seepage. Detection of a liner break necessitates emptying into an adjacent pond and locating and repairing the failure.

Pond height can be estimated by assuming a 6 to 12 inch soil cover over the liner, about 4 feet of accumulated salt precipitate for a 15-20 year disposal operation, 1 to 1.5 feet of liquid depth, and a freeboard of 2 feet (cumulative depth 8 to 10 feet). Banks should slope approximately 2:1 (horizontal to vertical) and be lined and soil-covered in a manner similar to the base. Allowance for width along the tops of embankments will accommodate vehicles for use in maintenance and weed control. All banks require compaction for stability. An estimate of the fill material needed for the finished earthwork will require preliminary in-place density measurements.

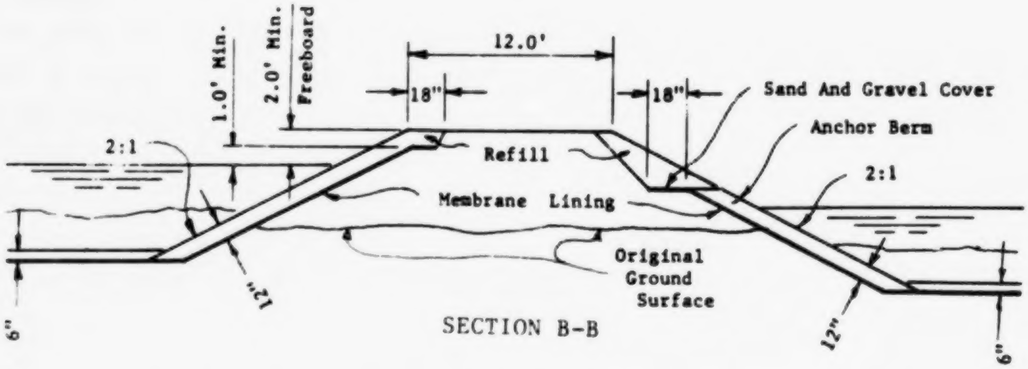
The operator is advised to consult state regulations when an evaporation pit is abandoned. Common procedure is to install an impervious, corrosion-resistant liner over the dried residue of the pond at a point level with the



PLAN


Anchor Berm
Provide Surface Drain If Required
12.0'
18"
2.0 Min. Freeboard
1.0' Min.
Sand And Gravel Cover
Accumulated Salt
2:1
Refill
Compacted Embankment
Original Ground Surface
Membrane Lining
12"
Earth Cover
6"

SECTION A-A


1.0' Min.
2.0' Min. Freeboard
12.0'
18"
18"
Sand And Gravel Cover
Anchor Berm
2:1
Refill
2:1
Membrane Lining
Original Ground Surface
6"
12"
12"
6"

SECTION B-B

Figure 3. Typical Plan and Sections for Brine Disposal Ponds.[24]

bottom of the freeboard. Then a 2-foot layer of earth is placed on the liner and lightly compacted. Finishing of the surface will depend upon the geographic area (forested, sandy, or grassland terrain).

Operation

Inflow to ponds is an operation requiring regulation to prevent scouring of earthwork. Damage to embankments from erosion and scour should receive early attention. The recommended liquid depth in ponds is 1 to 1.5 feet. While a lesser depth offers higher evaporation rates, extremely shallow water levels subject flexible liners to drying and cracking, especially if inflows are intermittent. Greater liquid depths do not take full advantage of the increased evaporation rate brought about by solar heating of the liquid mass.

Several methods of increasing evaporation rate have been advanced. The addition of dyes has been shown to have marginal benefit in increasing solar heating of the fluid body.[24, 25] A liquid surface free of oil and floatable materials is imperative for good evaporation. Oil films can exist as thin as 1.5×10^{-6} inch,[11] meaning that under proper conditions 25 gallons of oil could coat one square mile of liquid surface. Increasing evaporation rate by use of a spray system relies on the theory of exposing more water surface to air by atomizing the water mass. Studies have revealed that under the right circumstances increased evaporation of brine can be realized at a cost savings. Consideration must be given to spray nozzle type, spray configuration and capacity, corrosion-resistant materials, and maintenance.

Table 6 summarizes evaporation pond information.

INJECTION

Increased attention to ecology and pollution control has led to the adoption of more stringent state brine disposal regulations and to stricter enforcement of those regulations, particularly as regards surface disposal methods such as evaporation pits and direct discharge to streams.

Table 6. SUMMARY OF EVAPORATION POND INFORMATION

Advantages	Disadvantages
1. Elevated brine temperature beneficial.	1. Extremely high potential for groundwater and surface water pollution, due to failures in the system during the life of the pond and because of the extensive salt deposit remaining after the pond is abandoned.
2. Relatively quick to construct and easy to maintain.	2. Source of continuing legal scrutiny because of history of land scarring and water pollution.
3. Only oil and other film-creating floatable materials need be removed prior to disposal, implying minimal water treatment.	3. High land costs may make this method impractical.
4. Most effective in relatively arid sections of the country where land costs are relatively low.	4. Can be used only where high evaporation rates combine with low land costs.
5. Frequently the least expensive brine disposal alternative, especially in arid areas of the country.	5. Oil film on brine surface can seriously affect evaporation process.
6. Brine quality, except for oil content, is not a major problem in the operation of an evaporation pond.	6. May be difficult to find a reasonably priced liner resistant to chemical degradation of some brines.

Thus, the alternative to surface disposal, subsurface injection, is becoming more accepted legally and, in fact, has been used effectively for many years.

The design and operation of injection systems are regulated by many of the producing states, mainly to safeguard groundwater resources. Groundwater moves very slowly. Consequently, salt buildup usually is detected only after an extensive portion of the aquifer has been contaminated, requiring perhaps centuries to recover via natural recharge. The operator is advised to consult the exact regulations for injection systems in his state.

Brine may be returned to the formation of origin or be injected into another formation (oil bearing or not). In addition to being a disposal avenue, injection into the producing formation serves in maintaining reservoir pressure, thereby retarding the gradual decline of primary oil production. Waterflooding, on the other hand, is a secondary recovery operation that utilizes injected water under pressure to drive the oil to the producing well. Waterflooding is normally begun late in the primary recovery period, usually after the formation pressure has declined.[26] Both operations increase the recovery of oil in place, and both require volumes of water often in excess of the brine production. Brine satisfies an economic need in this case.

Important design considerations include selection and analysis of a receiving formation, creation of a new injection system versus renovation of an old production well(s), unitization of the disposal system, and choice of equipment and materials. Operational parameters are also significant: brine pretreatment, compatibility with receiving water and makeup water, injection pressure, and remedial measures.

Design Considerations

Selection--

The intent of a brine injection system may be the maintenance of formation pressure as petroleum is withdrawn, the recovery of oil by waterflooding, or simply the disposal of brine. The selection of the receiving formation should be based on geologic as well as hydrologic relationships in order to ascertain the injection capacity of the formation and the chemical compatibility of the injected brine and the water within the formation. The important region-wide geologic characteristics of a disposal formation are areal extent and thickness, continuity, and lithological character. This information can often be obtained from existing geologic maps, such as those of a producing oilfield. On a local basis, it is necessary to know formation depth and thickness, stratigraphic position, lithology, porosity, permeability, reservoir pressure, and temperature. This information can be obtained or estimated from core analysis, examination of bit cuttings, drill stem test data, well logs, driller's logs, and injection tests.[27]

The desirable characteristics for a waste injection formation are:[28] an injection zone with adequate permeability, porosity, and thickness; an areal extent sufficient to provide liquid-storage at safe injection pressures; and an injection zone that is vertically below the major freshwater zones and is confined by an overlying consolidated layer which is essentially impermeable to water. Knowledge of the vertical confinement and lateral movement of water within the prospective injection zone is an assurance against saltwater movement into groundwater and onto the ground surface.

There are two common types of intraformation openings: (1) intergranular and (2) solution vugs and fracture channels. Formations with openings in the first category are usually made up of sandstone, limestone, and dolomite formations and often have vugulor or cavity-type porosity. Also, limestone, dolomite, and shale formations may be naturally fractured. The second type of formation opening is often preferable for waste disposal because fracture channels are relatively large in comparison to intergranular openings. These larger channels may allow fluids high in suspended solids to be injected into the receiving formation under minimum pumping pressure and with a minimum amount of water treatment at the surface.

As a basis for further consideration in the selection process, mathematical relationships have been derived which predict the receptivity of a formation to injected fluid[15, 17] and the change in intake rate per unit of time.[29] The information derived through their usage should be regarded as approximation, for the reason that the conditions upon which the formulae are based do not necessarily hold for the prospective injection zone. Finally, the selection of a suitable location for waste disposal could depend on the local incidence of earthquakes,[28] which cause movement along faults, can damage wells in the area, and may be enhanced by pressurizing formations. Earthquakes have thus far not been a problem in conjunction with oilfield brine disposal; however, the fault zone aspects should be considered.

Installation--

The installation of a brine injection system may be via conversion of a marginal oil-producing well, work-over of an abandoned well, or drilling and completion of a new well. If the depth of hole reaches the anticipated injection zone, a converted well may be more economical, especially if leak-free casing is present. However, this route may be precluded if cement plugging and crooked casing strings are encountered or if the existing casing is too small to accommodate injection tubing. The advantage of planning a new well is the assurance that the well is drilled and completed properly, thereby safeguarding potable groundwater.

The American Petroleum Institute[30] lists the following accepted techniques:

1. Drill a full-sized hole to total depth and set the well casing through the porous disposal zone or zones. This method is recommended for unconsolidated formations subject to sloughing or caving.
2. Drill a full-sized hole through all porous zones or to a point where circulation is lost and set the casing immediately above the porous disposal zones.

3. Drill a full-sized hole to a point immediately above, or to the top of, the disposal formation and set the casing at this point. Then drill a reduced-sized hole through all the porous zones or until circulation is lost. If possible, clear water should be used for drilling fluid in drilling the reduced hole to prevent plugging from mud and lost circulation material.
4. Drill a full-sized hole to a point immediately above, or to the top of, the disposal zone, then drill a reduced-size hole to total depth and set the casing at the point where the hole size has been reduced. After the casing has been set, ream the rat-hole or reduced hole to remove the mud, using water for the drilling fluid. If the casing and hole size permit, the rat-hole may be reamed with a larger-diameter bit in a conventional manner. If conventional reaming cannot be done, the rat-hole may be underreamed.

Liners are often used when converting an old well for injection purposes to protect fresh water and other mineral bearing formations. Open hole completions are preferred in consolidated formations due to increased permeability and ease of cleaning, while an unconsolidated formation may require that casing be set through the formation and perforated. Other possibilities in the case of unconsolidated formations include a gravel pack or screened liner. It may be possible to improve the well permeability (ease of flow) of the formation face and mud invasion zone by circulating clear water, scratching or reaming the open hole, or swabbing to induce a backflow of fluid from the formation. Often it is necessary to increase the permeability in the vicinity of the well bore by acidizing in the case of limestone or dolomite formations or by hydraulic fracturing (see Figure 4).

There are many methods of completing injection wells for the disposal of brine or other liquid wastes. The wells can be completed with or without

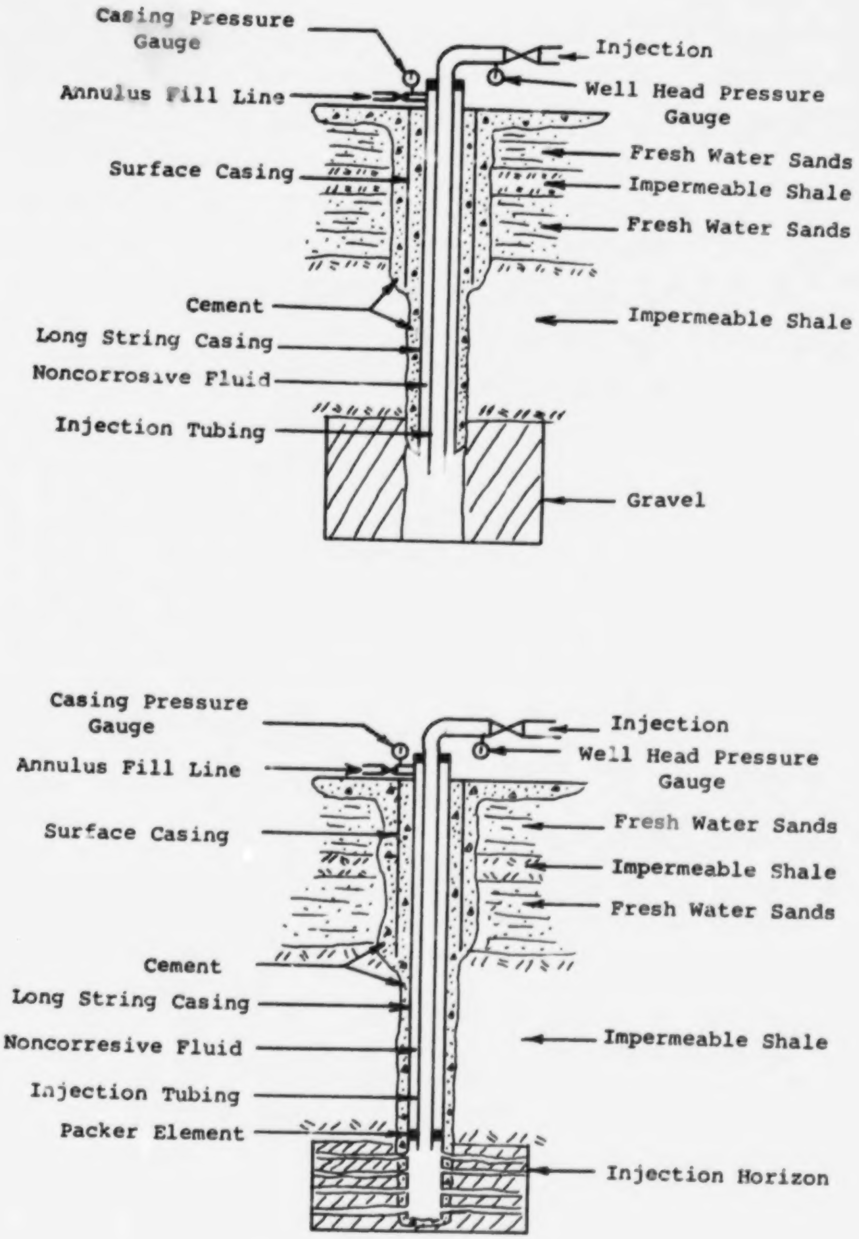

Casing Pressure Gauge
Injection
Annulus Fill Line
Well Head Pressure Gauge
Fresh Water Sands
Surface Casing
Impermeable Shale
Fresh Water Sands
Cement
Impermeable Shale
Long String Casing
Noncorrosive Fluid
Injection Tubing
Gravel
Casing Pressure Gauge
Injection
Annulus Fill Line
Well Head Pressure Gauge
Surface Casing
Fresh Water Sands
Impermeable Shale
Fresh Water Sands
Cement
Long String Casing
Impermeable Shale
Noncorresive Fluid
Injection Tubing
Packer Element
Injection Horizon

Figure 4. Open and Closed Hole Injection Well Completions.[45]

a packer (a special tool usually used to seal off the annulus between the tubing and casing). Packers are sometimes necessary to protect the casing from high injection pressures and are also used to protect the annulus from the corrosive effects of the brine by preventing the escape of brine up the annulus. After setting the packer, the annulus should be filled with a noncorrosive fluid such as kerosene, diesel oil, naphtha, crude oil, or chemically treated water, although it is also possible in many cases to use these fluids in the annulus without the benefit of a packer. The purpose of this operation is to replace the water that normally fills the annulus of the well with a noncorrosive fluid in a quantity sufficient to pressure balance the brine in the tubing at static conditions. If the static fluid level in the tubing is not high enough to support a column of noncorrosive fluid in the annulus, a packer must be used.

Corrosion and unseating difficulties in brine injection wells make the use of packers desirable only when absolutely necessary. As injection commences, resistance to flow in the tubing and formation causes the fluid in the tubing to rise, with a subsequent rise of the fluid in the annulus. A record of casing-head pressure along with injection rates taken at bimonthly intervals can reveal the following indicators in the operation of an injection well:

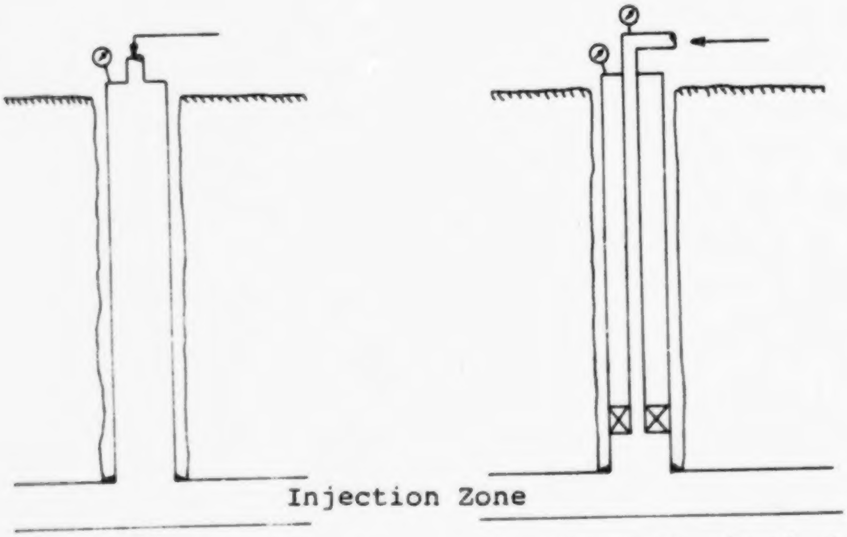
1. A constant injection rate and an increase in pressure indicate the formation is becoming plugged.
2. A decrease in injection rate at a constant pressure or an increase in injection pressure indicates an increased friction head in the tubing due to scale formation.
3. A constant rate or a greatly increased rate and a sudden decrease in pressure indicate a tubing or casing leak with possible pollutional consequences.

A variety of types of completions are presently being used for injection service; however, not all of these are satisfactory from a pollution-control standpoint.[31]

As mentioned previously, discussions with regulatory officials in several states indicate that improperly plugged, abandoned wells are the major sources of brine pollution. Many of these wells either do not have cement plugs or have a top plug and no bottom plug. If improperly plugged, the well may leak at the ground surface, in which case it can be detected and remedied. A single top plug or a faulty cement job is extremely difficult to detect and poses a continuous threat to fresh groundwater. Compounding the problem is the lack of recorded information regarding wells drilled prior to about 1940, many of which are now abandoned and whose locations are unknown.

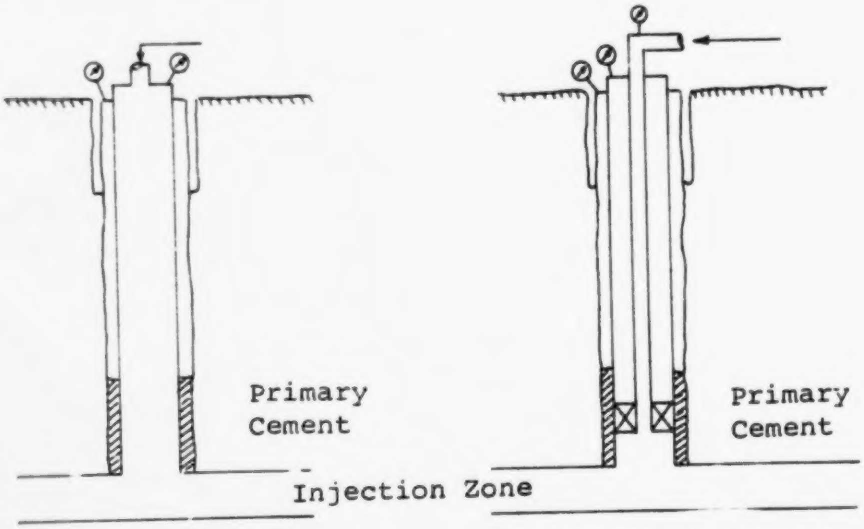
A review of the various types of completions presently being used for injection are shown in Figure 5. The type D completion is encouraged for brine injection because it can be effectively controlled and checked by surface tests. The following recommendations are presented for effective subsurface injection operations:

1. Design well completions for fluid injection and saltwater disposal service that may be effectively monitored and controlled by surface tests.
2. Give due consideration to environmental conditions in the project area.
3. In the design of saltwater disposal systems, select zones that have sufficient reservoir volume to accept the present and expected volume of produced water without developing overcharged conditions in the formation.
4. Control operating conditions of injection systems to avoid mechanical failure.
5. Encourage field personnel to be zealous in their checking of operating systems so that trouble may be detected and remedied at an early date.
6. Attempt to design water treatment programs that will also control failures due to corrosion.


Injection Zone

A. Cement Circulated, Injection Down Casing.

B. Cement Circulated, Injection Down Tubing.


Primary Cement
Primary Cement
Injection Zone

C. Cemented Surface Pipe, Injection Down Casing.

D. Cemented Surface Pipe, Injection Down Tubing.

Figure 5. Typical Injection Well Completions.[29]

7. Keep detailed records of injected volume and produced volume so that any loss of injected fluid might be detected and remedied at an early date.
8. Give careful consideration to state regulations regarding depth and cementing of surface casing, landing of the long string, injection through tubing below a packer, and monitoring of casing-head pressure.

Materials--

The corrosive nature of brine, particularly where dissolved oxygen and sulfides are present, dictates the usage of special materials in the injection system. Tubing and casing should be internally lined with plastic or cement to prevent the bare metal from contracting brine. In some instances, epoxy resin-lined tubing has been used successfully.[32] Unlined steel tubing is susceptible to corrosion and accumulation of scale and will eventually exhibit flow characteristics inferior to plastic-lined and epoxy resin tubing which are not susceptible. Care must be exercised when handling or running tools in the lined casing to prevent cracks or breaks in the lining. The pipe should be carefully inspected before being run downhole.

Two types of pumps are used for fluid injection. Centrifugal pumps are used for high volume service where the injection pressures are less than about 300 psi, and reciprocating, positive displacement pumps are necessary for pressures greater than 300 psi.

The piston-type duplex pump and the plunger-type inverted triplex are used in the East Texas oilfield.[33] Duplex piston pumps are generally used for pressures up to 500 psi, whereas the triplex pumps have been found to be suited for higher pressures. A primary consideration in pump design is the selection of the proper materials for saltwater service. The usual oilfield fittings such as pistons, liners, rods, valves, seats, and packing cannot be used in brine service because the salt water provides little lubrication and is extremely corrosive. The East Texas Salt

Water Disposal Company reports that liners made from "Janney 30," Monel, and "Ni-resist" are fully satisfactory from both the corrosion and wear resistance standpoint.[17] In the same operations, rods made of 303 stainless steel, with valves and seats of aluminum-bronze and magnesium-bronze, have also proven satisfactory.

Testing--

Following completion of a disposal well, well testing will describe its ability to receive brine. Injectivity index and capacity index are two such tests which measure the effective permeability of the disposal well and disposal formation as a whole. The capacity index is defined as barrels of brine injected divided by the increase in bottom-hole pressure (psi). This value can be determined by measuring the static bottom-hole pressure and the bottom-hole pressure at the maximum possible flow rate, and dividing the quantity injected by the corresponding pressure change. The tubing or casing should be kept filled, if possible, during the test, and flow should be continued until a stabilized rate is established. A well taking fluid under vacuum indicates that the formation is capable of fluid injection at a higher rate than that being delivered, but this is not necessarily an indication of the capacity of the well.

Injectivity index is similar to capacity index. It is defined as the change in the number of barrels per day of gross liquid injected into a well divided by the corresponding pressure differential between mean injection pressure and mean formation pressure, referring to a specific subsurface datum (usually this is the mean formation depth).[29]

One way to determine the injectivity index is as follows. Shut down the well until the transient back pressure is falling very slowly, which probably will take several hours. This means that the pressures in the formation around the well bore have become equalized. Begin injection and maintain a steady pressure for a short period of time (e.g., 5 minutes). Record the volume injected during the period--or, if possible, record the instantaneous rate at the end of the period--then raise the pressure in equal increments (e.g., 100 psi), taking additional volume readings. Follow this procedure until enough points are obtained to establish the relationship between intake rate and pressure. The resulting graph should be a straight line, the slope of which is the injectivity index. A simple plot of injectivity index versus time can indicate when the injection formation is plugging and that remedial action is necessary. Capacity index tests should be performed periodically (e.g., monthly) on each well to determine any changes in the injection capacity.

OPERATIONAL CONSIDERATIONS

Treatment

Brine receives treatment prior to injection. Treatment procedures depend upon whether brine is handled in an open or closed system. The closed system prevents brine/air contact and thus helps maintain the fluid's chemical equilibrium by alleviating the problems arising from oxygen-induced corrosion, scaling, and chemical precipitation. Other factors which threaten chemical equilibrium are the pressure and temperature changes that occur when the fluid comes from the reservoir to the surface. In a completely closed system the only treatment necessary is the removal of entrained oil and suspended solids and, on occasion, the addition of biocides. There is some doubt as to the feasibility of maintaining a completely closed system in normal oilfield practice[34] because of the many points in a disposal system where air can leak into the system, but some operations can be designed with a minimum of air contact (semi-closed systems).

Open (presence of air) systems are by far the most common type of disposal system and usually require more extensive treatment of the brine before injection because of oxygen-induced changes in the brine's chemical equilibrium. The treatment generally involves removal of the dissolved gases, suspended solids, some dissolved substances, and possibly dissolved oxygen. In addition, biocides may be added to eliminate bacterial clogging of the formation.

The chemical and physical nature of the disposal formation and the water within it determines, in large measure, the degree and extent of the water treatment necessary prior to injection. Some limestone and dolomite formations will take untreated brine under a vacuum; some sandstone formations require that the brine be treated to a high degree. If the injected brine is incompatible with the formation brine, precipitates may form upon contact of the two, eventually plugging the face of the formation in the vicinity of the well bore.

Injection Pressure

The maximum bottom-hole injection pressure is a regulated parameter. The purpose is to prevent formation fracturing and possible escape of brine into freshwater aquifers. Some state regulatory agencies recommend a maximum figure of 0.5 psi per foot of depth. In the case of deep wells, this value may be reduced to 0.4.

Remedial Measures

During the life of an injection well, capacity may decrease significantly due to formation plugging (from suspended solids, precipitation, hydrocarbons, or bacteria) or fouling of flowlines from scale. The following remedial measures have been used to increase capacity.

1. Acidizing. Hydrochloric acid will remove most scales with the exception of barium sulfate, strontium sulfate, and calcium sulfate which may have to be removed mechanically by scraping or reaming with a drill bit. Hydrofluoric acid will dissolve sand, clay, or mud if these are the plugging agents. A detergent may be added to the acid to help remove oil films from the reservoir and facilitate the acid reaction with rock.
2. Hydraulic fracturing. In this technique, a fracturing fluid can be introduced into the formation with sufficient pressure to induce horizontal fractures in the formation, thereby increasing permeability. A material, such as coarse sand, is pumped with the fluid

to act as a propping agent to maintain permeability after the pressure is released. Brine, which is normally injected into the formation, is the logical "hydrofracing" fluid. Care must be taken not to apply excessive injection pressures which could cause tubing failures or vertical fractures communicating with fresh water.

3. Backflowing. Under certain conditions, wells can be backflowed to clean the formation face. Occasionally special strings of tubing are used to facilitate this operation.
4. Mechanical cleanout. In cases where large deposits of hard scale are formed on the formation face, tools such as reamers and bits may be used to restore permeability.
5. Chlorine and other chemicals. The injection of chlorine has in some instances doubled the rate of input into injection wells.[35] The reasons for this improvement were theorized as:
    a. Chlorine in water solution forms hypochlorous acid which dissolves carbonate deposits.
    b. Chlorine kills bacteria and thus reduces plugging caused by bacterial slimes.

Carbon disulfide has been used as a solvent for free sulfur, which can collect on the formation face. However, the toxicity and highly flammable nature of carbon disulfide make it extremely dangerous to handle.

Detection of Salt Pollution

A series of techniques can be employed in the detection of salt pollution in the injection systems.[33] Combinations of these methods are recommended for each individual case:

1. As background information about the geographic area in question, review the history of the field, the salt-water disposal methods and volumes, and the salt pollution. Also study the local geology and hydrology.
2. Isolate the problematic injection well or pit by conducting area-wide surveys. Obtain groundwater samples which characterize the natural (unpolluted) chloride levels in the freshwater formations of concern. Sample existing domestic and irrigation wells and other test holes. If several disposal systems are in operation, a program of selective shutdown may reveal the faulty system by the process of elimination. Ultimately, construction and sampling of a network of permanent test wells may be required.
3. Suspected failures in injection wells can be verified by several tests:
    a. Records of casing head and injection pressures.
    b. Additive Tracer Test. Dyes are added to injected water and observations made in seepage areas.
    c. Pressure Falloff Test. This is a test to further detect a casing leak, or channeling, by comparing several wells operating under similar conditions.
    d. Injection Well Performance. Overcharging of the injection zone can be detected by running performance tests at intervals (e.g., every 6 months) throughout the life of the well. The test is run over a 48- to 72-hour period with alternating shut-in, injection, shut-in cycles. An increasing shut-in pressure indicates overcharging with possible pollutional consequences.

e. Relative Injectivity Tests. Two methods are available:

   (1) Plot the location of the injection wells on a map with their respective injection ratios (i.e., injection pressure/injection rate). Any large deviations can indicate casing leaks or channeling.

   (2) A graph of rate-pressure profiles for several different wells should show similar slopes. Any large deviation in slope is evidence of a casing leak or channeling.

f. Subsurface Tracer Surveys. Tracers such as dyes or radioactive material are injected into the disposal formation; a corresponding detection test run in the casing can indicate casing leaks and channeling.

g. Wire-Line Plug Method. It may be possible to pump a cement plug down the well and have it stop at a point just below a casing leak by checking the well pressure as the plug is lowered.

h. Temperature Survey. Distinct changes in temperature may indicate a possible casing leak.

i. Pipe-Inspection Logs. These may be used by an experienced operator to detect holes in casing.

j. Subsurface Pressure Gauge. Running a pressure profile may show a shift in the graph just below the leaks.

k. Packer and Tubing Test. A packer which has been set up to allow pressure in the tubing, casing, and annulus could be set at various points in the casing. This procedure would divide the pressure falloff section of the annulus from the section where pressure doesn't fall off, thus isolating a leak.

SECTION IV

BRINE WATER TREATMENT

Oilfield brine water treatment is a process whereby the brine is in some way altered to reduce the unwanted effects of scaling or corrosion, or to remove any other conditions that might hinder disposal. While brine water treatment is predominantly the problem of the injection system operator, scale and corrosion effects are of general importance to all operations that involve the separating, transporting, and/or handling of oilfield brine.

Although more specifically explained in electrochemical terminology, corrosion might be visualized as a phenomena that occurs when a constituent in the brine has a stronger attraction for an element in the material of the brine handling system (pipeline, tank, etc.) than the system itself possesses. Thus, the element is literally pulled out of the system and combines with the material in the brine which exerted the stronger attraction. As would be expected, corrosion damage normally appears in the form of holes or similar depressions in the inside surface of the brine handling system, usually in areas of higher fluid velocity. Treating brine to prevent corrosion involves either removing the strongly attractive brine constituent or altering the nature of the brine to reduce the strength of or eliminate the corroding agent. An alternative to brine treatment for corrosion is to line the inside of all brine containers and piping with a nonreactive material.

Scaling, on the other hand, may be visualized as the opposite effect of corrosion. Scaling generally occurs as a result of conditions in the brine which cause a constituent(s) to be removed by chemical reaction or precipitation. Scaling damage is normally in the form of mineral deposits on the inside surfaces of the brine containers or pipes, usually at areas of lowered fluid velocity. These deposits gradually clog up the pipe openings increasing the amount of pumping necessary to move the fluid. Treating brine to prevent scaling broadly involves removing the potential scale-forming brine constituents or altering the nature of the fluid to keep the potential scale formers in solution (dissolved).

Another factor that might create disposal problems and require treatment of the brine is fluid incompatibility. Like corrosion and scaling, incompatibility is a chemical effect. Unlike those problems, however, incompatibility is most troublesome in brine injection reservoirs. Generally, incompatibility occurs when one or more of the chemicals in the brine reacts with chemicals in the existing reservoir fluid to cause an undesirable effect, such as precipitation. Precipitation damage resulting from incompatible fluids is usually in the form of plugged pore spaces in the injection zone. Treating brine to prevent incompatibility consists of reducing the strength of or removing the reactive element, or altering the nature of the injected fluid. Alternatives to treatment include selection of another legally acceptable disposal method or another injection zone. The last two brine handling/disposal problem areas are suspended solids and excessive amounts of oil. Suspended solids may be organic or inorganic. If the solids are organic, then bacteria may also be present in the brine, especially if the organic material is present in relatively high amounts. These bacteria can prove excessively troublesome not only at the injection well interface but throughout the entire brine gathering system. The most damaging effects of bacterial action include release of soluble SO_4 which reacts to form hydrogen sulfide (H_2S), and the physical clogging of injection reservoir pores. Treatment usually takes the form of filtering and the addition of a good bactericide. If high amounts of dissolved and suspended organic materials are present, more elaborate treatment devices or alternate legally acceptable disposal methods may be required. Inorganic suspended material may cause the same brine disposal problems as precipitation and scaling.

The addition of oil magnifies disposal problems considerably. Oil coagulates around inorganic solids and binds them together. The effect is to produce a type of gel which can plug the injection interface. Treatment may consist of removing the inorganic solids by filtering, by chemical-aided settling, or by removing a higher percentage of the oil before it gets to the disposal system.

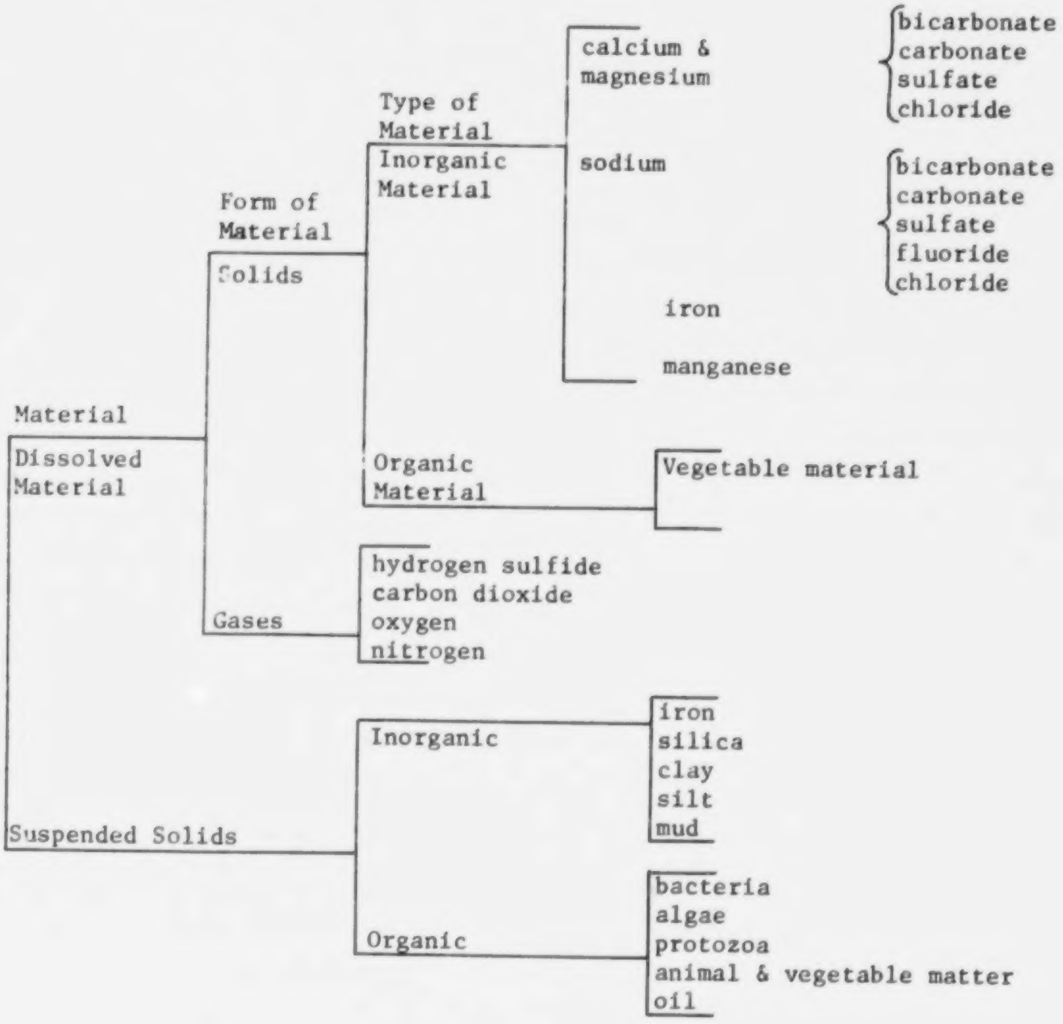
DEGREE OF WATER TREATMENT[32, 36]

The degree of water treatment required in a brine disposal project depends on the constituents in the water, the type of disposal system (open or closed), the type of disposal mechanism, the kind of materials used in the well equipment, and the characteristics of the disposal formation (in the case of injection). In some instances, the combination of these factors is such that no water treatment, or at most a minimum of water treatment, is required. A closed system injecting a high quality brine into a very permeable formation may only require the addition of one or two chemicals to help prevent precipitation or corrosion. In all cases, a laboratory analysis of the brine must be made before the design of water treatment process can proceed. The common impurities of brine are shown in Table 7.

ANALYTICAL TESTS

The analytical tests that are normally run on brine to be injected are listed in Appendix C. The analytical procedures, reagents, and preparation of reagents for these tests are well described in Standard Methods.[37] A Bureau of Mines publication by Watkins also describes many of these tests giving field test procedures.[38] As Watkins explains, "In some of the tests extreme accuracy, such as required in an analytical laboratory, has been sacrificed for rapidity and convenience. However, for most of the tests, the methods described herein are accurate enought for plant-control purposes."[38]

Table 7. COMMON IMPURITIES IN BRINE[53]


Material
Dissolved Material
Form of Material
Solids
Type of Material
Inorganic Material
calcium & magnesium
bicarbonate
carbonate
sulfate
chloride
sodium
bicarbonate
carbonate
sulfate
fluoride
chloride
iron
manganese
Organic Material
Vegetable material
Gases
hydrogen sulfide
carbon dioxide
oxygen
nitrogen
Suspended Solids
Inorganic
iron
silica
clay
silt
mud
Organic
bacteria
algae
protozoa
animal & vegetable matter
oil

In addition to the tests listed in Appendix C, it is often desirable to run corrosion tests to determine the weight loss for various metals expected to be used in the gathering system and disposal wells. This is accomplished by flowing the brine past a corrosion coupon (sample of the metal to be tested) that is rigidly suspended in the stream. The rate of corrosion is determined by weighing the coupon at various time intervals. Visual examinations of these coupons can also indicate the type of corrosion in some instances.

Membrane filtration tests are often used in determining the overall plugging tendencies of the suspended solids in water being injected. Membrane filters are made of cellulose ester or polyethylene and range in pore size from about 10 microns to 0.45 microns (the 0.45 micron size is used in the membrane filter test). The membrane filtration test is usually carried out at 20 psi pressure, and the volume of filtrate is determined as a function of time. From these tests, a graph of flow rate (ordinate or vertical values) versus cumulative volume (abscissa or horizontal values) is obtained, the slope of which indicates the quality of water. A horizontal line indicates perfect water for injection purposes, while a slope greater than 1.8 indicates poor water. Plugging tendencies can only be evaluated when the results of filtration testing are coupled with compatibility studies.

Microscopic examination is also advisable to determine the presence of microorganisms. Bacteria are the primary microbial offenders in the disposal systems of oilfield brines and can be a source of both corrosion and formation plugging. If a microscopic examination reveals the presence of appreciable quantities of microorganisms, a more detailed examination should be conducted in a suitable laboratory to determine appropriate treatment devices.

FORMATION PLUGGING AND SCALING

One of the major objectives in brine treatment is to prevent the deposits of solid material in the gathering system or, in the case of injection, in the formation surrounding the well bore.

As brine is produced from an oil well, its temperature and pressure decrease. An increase in temperature increases the solubility of most salts and gases. On the other hand, a decrease in pressure decreases the solubility of gases. Therefore, the usual overall effects of bringing the brine to the surface are the precipitation of salts and the release of gases from solution

In injection, the compatibility of injected water and water already in the formation must be considered because a reaction between the chemical constituents of the two different waters may form insoluble compounds which precipitate. This condition could also occur if incompatible waters from different reservoirs or surface sources are to be mixed prior to injection.

DEPOSITS

To deal effectively with chemical and biological deposited materials, the operator must be familiar with their specific natures and reactions. The substances most commonly deposited by oilfield brines are:

1. Calcium carbonate or calcite ($CaCO_3$); scale.
2. Magnesium carbonate ($MgCO_3$); scale or sludge.
3. Calcium sulfate ($CaSO_4$); scale.
4. Barium sulfate ($BaSO_4$); sludge.
5. Iron compounds; corrosion products.
6. Biological deposits.

Calcium Carbonate ($CaCO_3$)

The solubility of calcium carbonate in oilfield waters is influenced by the partial pressure of carbon dioxide (relative amount of the CO_2 gas dissolved in the brine compared to the amount in the atmosphere), brine temperature, pH, and the concentration of other salts in the brine. Dissolved calcium carbonate does not exist in solution as calcium ions (Ca^{++}) and carbonate ions (CO_3^{--}) but as calcium ions and bicarbonate ions (HCO_3^-). Calcium carbonate is formed according to the equation:

$$Ca(HCO_3)_2 = CaCO_3 + H_2O + CO_2 \tag{3}$$

Decreasing the pH or increasing the carbon dioxide partial pressure would drive the equation to the left (i.e., increase the concentration of calcium bicarbonate and decrease the amount of calcium carbonate scale). Likewise, an increase in the brine pH, corresponding to a decrease in the carbon dioxide partial pressure, would cause calcium carbonate to be deposited. The latter condition usually exists when pressure is released as the brine is produced from an oil production well.

The loss of carbon dioxide from solution in brines is a function of the pH changes in the solution. If the pH of the water is near 8.0, the calcium carbonate will exist in solution as about 2% carbonate ion, 93% bicarbonate ion, and 5% carbon dioxide gas dissolved in water. If the pH were at 7.0, there would be only a trace of carbonate ions, 80% bicarbonate ions, and 20% carbon dioxide gas dissolved in the water. As discussed previously, most brines rarely exceed pH = 9.0. In fact, the usual range is pH 5.5 to pH 8.0.[39]

The decrease in both temperature and pressure in produced waters coming to the surface decreases the solubility of calcium carbonate, but in nearly all instances the loss in pressure exerts the greater effect.[39] A decrease in the temperatures of brine being injected into a well decreases the solubility of calcium carbonate. This partially explains plugging and scaling problems encountered by injecting brine at surface temperatures into lower temperature formations.

Several equations are available for predicting the calcium carbonate scaling tendency of water. One of these is the Stiff and Davis Stability Index[39] which is an extension of the Langelier method developed specifically for oilfield brines:

$$SI = pH - K - pCa - pAlk \tag{4}$$

SI is the stability index value. A positive value indicates scaling conditions, whereas a negative value indicates corrosion. The ideal condition is to maintain the stability index at zero so that neither scaling nor corrosion will occur. Values for K, pCa, and pAlk are obtained from graphs. The reader is referred to the Appendix section of Introduction to Oilfield Water Technology by A. G. Ostroff[39] for a more complete explanation of the method.

Magnesium Carbonate ($MgCO_3$)

Magnesium carbonate can be deposited as a scale or sludge, and its solubility in water is affected by the same factors as calcium carbonate. The difference is that magnesium carbonate is many times as soluble as calcium carbonate. Since most waters contain both calcium and magnesium, calcium carbonate would precipitate first, thereby reducing the carbonate ion content. Thus, magnesium carbonate is not likely to precipitate unless the magnesium content is extremely high. At high temperatures magnesium carbonate decomposes into magnesium hydroxide (and other reaction products) which may form deposits in the tubing in deep, high temperature wells.

Hydrated Calcium Sulfate ($CaSO_4$)--Gypsum

Calcium sulfate is common to oilfield brines and deposits as a scale rather than a sludge. It is more difficult to remove than calcium carbonate. Temperature variations do not influence calcium sulfate solubility as much as they do calcium carbonate, but a decrease in temperature may decrease the calcium sulfate solubility causing scaling. Carbon dioxide does not affect the solubility of calcium sulfate as it does with calcium carbonate and magnesium carbonate.

Calcium sulfate exists in nature as gypsum ($CaSO_4 \cdot 2H_2O$) or anhydrite ($CaSO_4$). The anhydrite form exists at high temperatures and may be found in deep wells. Metter and Ostroff have also developed a method for predicting the approximate solubility of calcium sulfate in oilfield brines.[39]

Barium Sulfate ($BaSO_4$)

Barium sulfate is very insoluble and very difficult to remove once formed due to its fine particle size. The solubility of barium sulfate increases slightly with increasing temperature and the presence of certain salts. Problems with plugging from insoluble barium sulfate can result from injecting sulfate-laden brine into a disposal aquifer containing soluble barium salts.

Iron Deposits

Iron deposits in disposal systems come from two sources, the water itself or the corrosion of iron or steel in the system. These deposits may form scale or remain in the water as colloids (suspended particles). Precipitates from iron and hydrogen sulfide reactions can cause iron sulfide scales. The presence of large amounts of dissolved oxygen can cause hydrated ferrous hydroxide and ferric hydroxide scales or deposits. Dissolved carbon dioxide can cause ferrous bicarbonate scales, which are loosely held on metallic surfaces and can flake off with resultant plugging of the injection formation.

Iron in natural waters exists in such oxidation states as ferrous (Fe^{++}) ions, ferric (Fe^{+++}) ions, or as complex ions. The pH of the water influences the solubility of the ionic form; that is, at pH values higher than 3.0 the ferric ions combine with hydroxide ions to form ferric hydroxide. The solubility of the ferrous ion may be controlled by the hydroxide (OH^-) ion concentration or the bicarbonate (HCO_3^-) ion concentration. Formation waters containing dissolved iron can deposit ferrous carbonate, ferrous sulfide, ferrous hydroxide, ferric hydroxide, and/or ferric oxide.

The oxidation state of dissolved iron (ferric or ferrous form) is useful in predicting its deposition tendencies. By using a method based on the oxidation-reduction potential of the water, the pH of the water, the bicarbonate ion concentration of the water, and an iron stability diagram, the maximum permissible concentration of dissolved iron can be estimated.[39]

Biological Deposits

Certain microorganisms which grow in disposal systems are able to corrode steel and form precipitates. Biological growths can also plug the injection reservoir formation face and such surface equipment as filters.[35] Algae and bacteria are the primary offenders; however, algae require sunlight and are able to grow only in open treatment systems. Under conditions where oilfield brines contain the necessary nutrients (chemical food materials) to support large bacterial growths, those organisms known as sulfate producers grow profusely.

TREATMENT REQUIREMENTS FOR SCALE PREVENTION

Treatment for scale prevention may be either physical or chemical. Physical methods include:[18, 36]

1. Separation and removal of incompatible constituents.
2. Prevention of conditions causing supersaturation (the chemical "excess" condition which must exist prior to precipitation and scale formation).
3. Elimination of air entry.
4. Use of some type of settling or filtration mechanism.

Certain scale-preventing chemicals are often added to brines as part of the treatment process. In chemical treatment, the prevention of scale deposition involves either removal of the anion or cation of the scale forming combination, or the addition of a chemical scale inhibitor which ties up the scale forming cation. The inhibitor usually chelates or complexes the cations so that they remain in solution and cannot combine with the appropriate anions. The process of tying up the ions in this manner is called sequestration.[40] Probably the most popular sequestering agents are the inorganic polymetaphosphates which are adsorbed on the surfaces of crystal nuclei and prevent their growth. Organic chelates such as EDTA (ethylene-diaminetetracedic acid) are also useful in scale inhibition. EDTA forms stable soluble complexes with magnesium, calcium, strontium, barium, and other divalent metals. Iron sequestering agents such as citric acid salts have also proven useful.

Case[18] reports that stabilization processes consisting of coagulation (mixing), settling in open basins, and filtration can prove expensive and difficult to control--to the point of being impractical. If such is the case (or for other reasons), chemical scale inhibitors may prove a more satisfactory answer to scaling problems. One major operator reported that after extensive testing:

1. Scale-preventing chemicals only worked on chemicals that yield a crystalline form (inorganic).
2. The most effective of the scale inhibitors tested were organic polyphosphonates.
3. Combination corrosion and scale inhibitors were relatively ineffective in reducing either scale or corrosion.

Case further points out that the disposal system operator should insist on regular check-tests to assure that the scale inhibitors are performing properly.

CORROSION

The corrosion of metals in a brine disposal system is usually caused by electrochemical reactions.[41] In this type of reaction an anode (electron donor) and cathode (electron acceptor) must exist in the presence of an electrolyte (ionic solution) and an external circuit. Anodes and cathodes can exist at different points on the steel surfaces with the steel providing the external circuit. A brine solution provides an excellent electrolyte. Thus, an electric circuit can be set up in the unprotected, brine-handling pipelines with iron being oxidized at one portion of the system (cathode) and iron being reduced and corroded away in another portion (the anode).

Corrosion damage can occur uniformly as a gradual thinning of the anode portion, or it can occur in the form of pitting where localized electrolytic cells are set up. It can also occur as galvanic corrosion when two different metals come into contact and form an electrolytic cell.

Dissolved oxygen is probably the greatest producer of corrosion. Oxygen-induced corrosion is the result of differences in oxygen concentrations in the system which cause an electrochemical potential difference. While oxygen is normally absent in formation waters, it is unavoidably absorbed by contact with air in the open system of oil production-disposal.

Dissolved carbon dioxide (CO_2) is not as corrosive as dissolved oxygen, assuming equal concentrations. Carbon dioxide is present in water as an integral part of the carbonate system; however, any carbon dioxide above that necessary to keep bicarbonate in solution is termed "aggressive" carbon dioxide and is free to dissolve in water and act as an acid. Thus, the pH decreases and the corrosion rate increases with an increasing partial pressure of carbon dioxide. Water containing both oxygen and carbon dioxide is more corrosive for equal concentrations than water containing either by itself.

Hydrogen sulfide (H_2S) is soluble in water and, when dissolved, behaves as a weak dibasic acid. Brine with dissolved hydrogen sulfide and oxygen may even be corrosive to acid-resistant alloys. The corrosion of mild carbon steel when exposed to a hydrogen sulfide solution increases to a maximum rate at around 400 ppm H_2S, then becomes fairly constant to about 2500 ppm H_2S. Corrosion rates for metals exposed to hydrogen sulfide in brine are higher than those exposed to hydrogen sulfide in distilled water. When carbon dioxide is present, the corrosion rates are still greater.

Dissolved salts greatly affect the corrosiveness of water. Sulfates ($SO_4^=$), chlorides (Cl^-), and bicarbonates (HCO_3^-) are among the most common anions in brine, with the sulfate ion having the greatest effect on corrosion. The effect of ions on corrosion depends upon the metal and the ion's ability to penetrate the protective coatings formed on the metal. The corrosiveness of waters with dissolved salts usually increases with increasing salt concentration up to a maximum, and then it decreases. The pH of the electrochemical solution influences the corrosion rate of most metals to a large extent.

Temperature can affect the corrosion rate in a rather complex manner; however, the corrosion rate generally increases with an increase in temperature. The corrosion rate will increase with a corresponding rise in temperature, reach a maximum, then decrease. The decrease is due to an appreciable decrease in the solubility of oxygen.

The effect of velocity on corrosion rate can be complex. The corrosion rate has been observed to increase as the velocity increased in small diameter pipes, possibly due to the effect of turbulence.

PREVENTION OF CORROSION

Corrosion can be prevented or at least reduced by certain brine treatments. De-aeration will remove oxygen, degasification will remove dissolved gases such as carbon dioxide and hydrogen sulfide, and water softening will remove dissolved calcium and magnesium hardness.

Chemical substances called inhibitors are often added to reduce or prevent corrosion. However, caution should be exercised in selecting a specific inhibitor because some of the inhibitors added in the incorrect concentrations can cause a corrosive condition themselves. These substances are both organic and inorganic in nature. The organic compounds usually form films on the metallic surface. Many inhibitors contain surface active agents that will remove loose scale when added for the first time and may cause plugging if precautions are not taken.

Corrosion can also be prevented by the use of coatings. Metallic coatings can be noncorrosive or sacrificial. The latter type protects cathodically, which is an electrochemical reaction that is imposed so that current and sacrificial metallic ions flow in a direction opposite to that which would normally occur. Other coatings used are vitreous enamels, cement, phosphate coatings, oxide coatings, paint, lacquer, and plastic. The correct choice of metals such as brass and Monel for brine service will prevent corrosion and reduce maintenance costs.

Cathodic protection is often used to protect metallic surfaces in contact with brine. In cathodic (active) protection of the submerged areas of equipment such as tanks and filters, an external current may be applied (an active system) such that the current enters all areas of the metallic surface that were previously anodic. Sacrificial anodes such as magnesium and zinc may be used (a passive system) in the protection of pipes and tanks.

TREATMENT SYSTEMS

Treatment mechanisms require careful design and regular maintenance, and considerable care should be used in their selection. Brine disposal systems are usually classified as closed (absence of air) or open (presence of air), although some systems employ features of both. Figure 6 illustrates a typical oilfield brine disposal scheme.

Closed System

A closed system does not ensure a stable water for reasons discussed under the topics of scaling and corrosion; however, by eliminating oxygen, precipitation of insoluble compounds and corrosion problems are usually minimized. In pressure vessels where oil water separation and emulsion treating are carried out, a closed system would be advantageous. In a closed system, an effort is made to maintain a blanket of natural gas over the brine in all of the pipelines and tanks, but experience has shown that complete air exclusion is very difficult. A complete closed system treatment operation usually consists of residual oil removal (probably in the form of a skimming tank), filtration and backwash, filtered water storage, and injection.

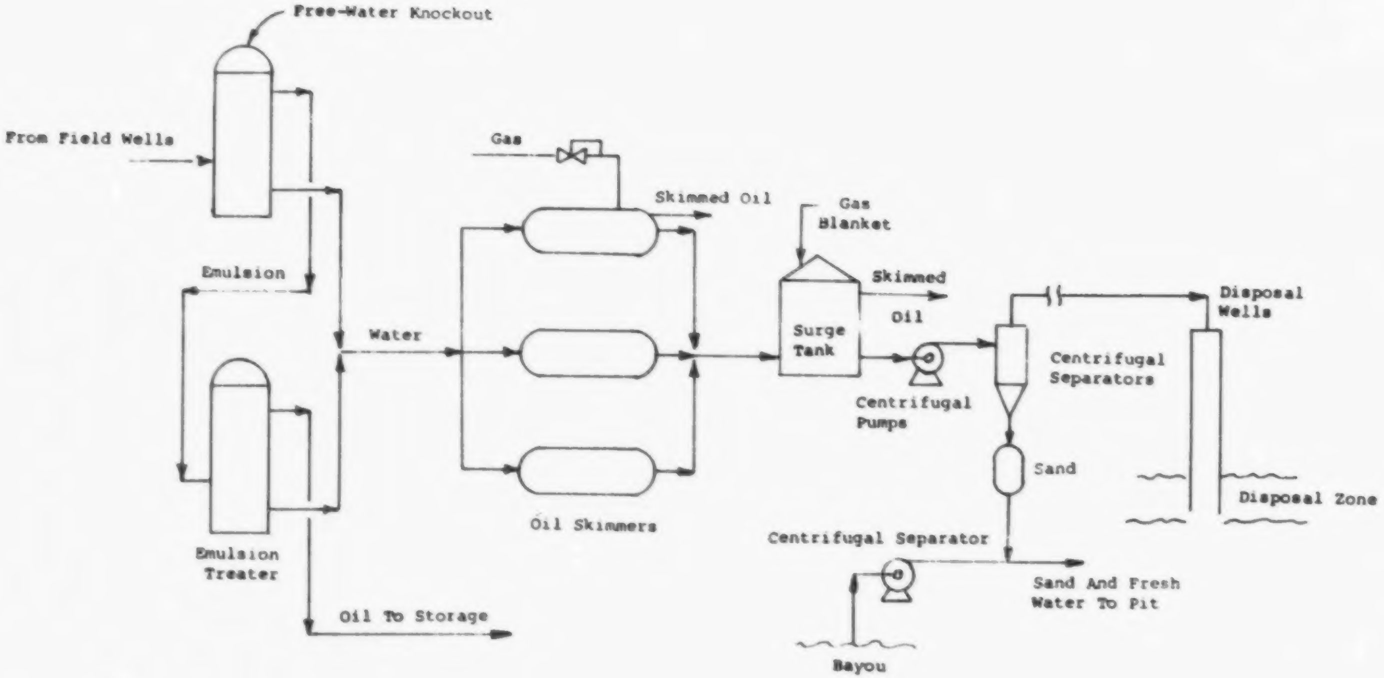

Free-Water Knockout
From Field Wells
Emulsion
Emulsion Treater
Water
Oil To Storage
Gas
Skimmed Oil
Oil Skimmers
Gas Blanket
Surge Tank
Skimmed Oil
Centrifugal Pumps
Centrifugal Separators
Sand
Centrifugal Separator
Bayou
Sand And Fresh Water To Pit
Disposal Wells
Disposal Zone

Figure 6. Typical Oilfield Brine Disposal Scheme (Bayou Sorrel SWD System - Shell).[46]

Open System

Open systems usually occur when the oil is separated from the water in open gun-barrel type separators or when the water is stored in open pits or tanks prior to its being introduced into the disposal system. A cooperative disposal system with many operators is usually of the open type since a variety of techniques and equipment is used to separate and store the water, much of which is open to the air. A completely open system usually consists of residual oil removal, aeration and degasification, chemical treatment including coagulation and settling, filtration and backwash, storage, and injection. The additional treatment is necessary since exposure to air results in a change in the carbon dioxide partial pressure, which may cause precipitation, as well as corrosion due to free hydrogen sulfide and dissolved oxygen. Algae and aerobic bacteria are also free to enter open systems.

OIL REMOVAL

Primary separation of oil from water is usually accomplished in free water knockouts, gun-barrel separators, or heater treaters. The efficiency of these processes is not always sufficient to ensure relatively oil-free water for introduction into the disposal system.

The ease of removing oil from water is greatly influenced by the chemical treatment or physical handling of the oil-water mixture before separation.[18] Examples include:

1. Overtreating producing wells with certain scale inhibitors can stabilize emulsions.
2. Certain types of corrosion inhibitors act as emulsifying agents when used in slug treatment.
3. Certain emulsion breakers can give very clean oil, but also very stable emulsions of oil in water.
4. Centrifugal pumps can form oil-in-water emulsions.

Gravity separators are generally used in disposal systems to remove as much residual oil as possible from the water. (Horizontal pressure vessels are often used in closed systems.) One section of the separator vessel has a mechanism to remove large droplets of oil and regulate the flow. Another section of the vessel is used for gravity separation. The oil rises and is skimmed off through a riser. Open systems often utilize large open concrete basins with baffles and slotted-pipe collectors to accomplish the separation and skimming. These basins are often similar to the conventional API separator used in oil refineries and may be wood or steel tanks. A typical skim tank is shown in Figure 7. A vertical baffle aids in gravity separation and the floating oil is skimmed off through a trough. Skim tanks are suited for both open and closed systems. Wood tanks are preferred in many instances for their corrosion resistance.

Dissolved gas flotation is a highly efficient method to remove oil from water if an oil-in-water emulsion does not exist.[18] Flotation is a process in which gases are dissolved in the water under pressure. On release of the pressure, bubbles form, become attached to the oil and particulate matter, and then float the oil matter to the surface where it can be skimmed off. If the flotation unit becomes overloaded when oil or emulsions are present, the addition of absorbent clays followed by a polyelectrolyte is recommended. Alum, a coagulant used in municipal water treatment, will also aid a flotation cell that is overloaded or receiving emulsions.

AERATION AND DEGASIFICATION

In open systems brine is aerated for two primary purposes. The first purpose is to drive all acid-causing gases (carbon dioxide and hydrogen sulfide) out of solution and reduce corrosion. The second is to oxidize iron and form precipitates which will be retained in the settling basins or on the filters, thereby preventing these precipitates from coming out of solution in another part of the system or in the formation. If manganese is present, it will also be oxidized and precipitated. Aeration has one disadvantage in that oxygen is dissolved in the water and will cause corrosion downstream in the system. For this reason, aeration should be carefully controlled.

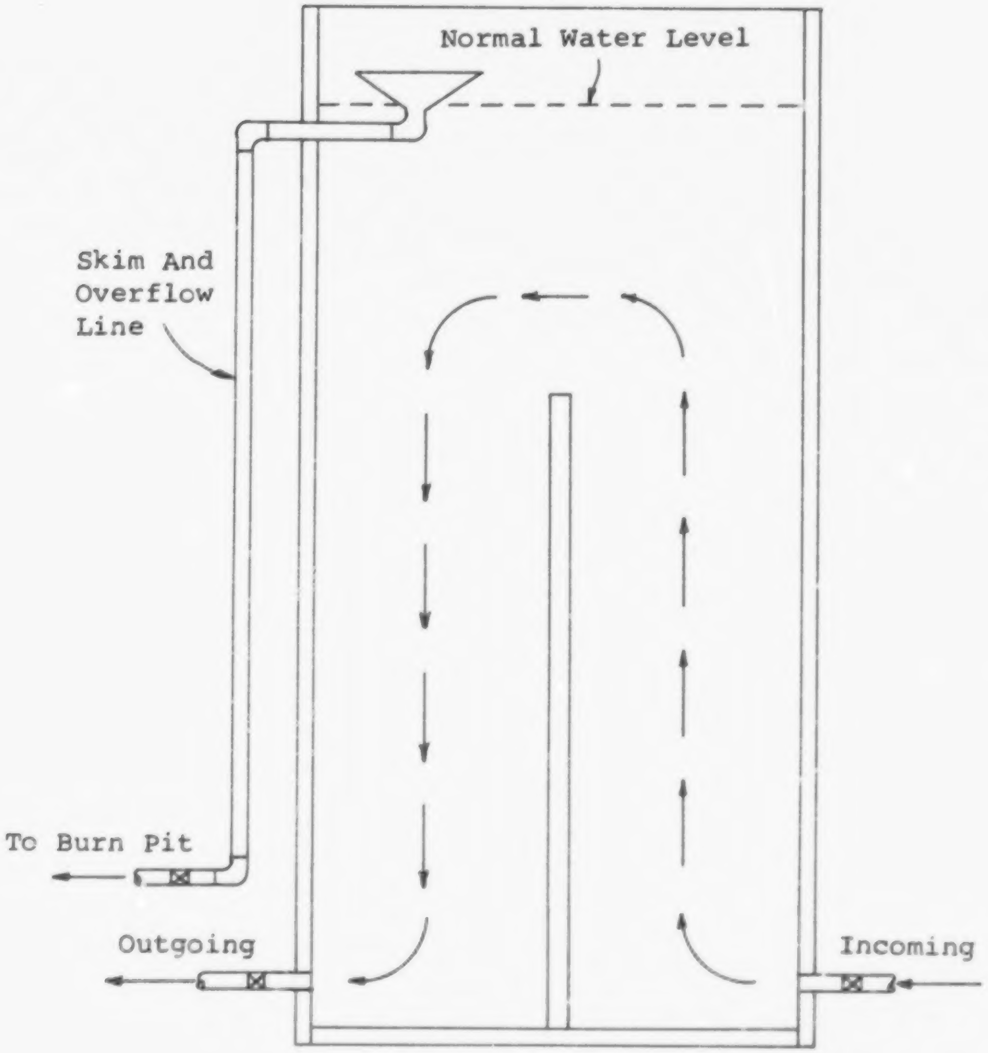

Normal Water Level
Skim And Overflow Line
To Burn Pit
Outgoing
Incoming

Figure 7. Sectional View of Skim Tank.[17]

Aeration equipment usually consists of spray nozzles, atmospheric towers where the water cascades over a series of splash trays, forced draft blowers where air is forced countercurrent to a flow of water cascading over splash trays, or free-fall or step-type aerators where the water falls on a spreader or tumbles down a series of steps.

COAGULATION AND SEDIMENTATION

Coagulation and sedimentation processes are used in open treatment systems to remove the suspended solids and precipitates that have formed due to equilibrium changes and aeration. In some disposal systems, sedimentation is employed without the help of chemical aids. The settling process in this case is known as plain sedimentation. The design of settling basins is based on the settling velocity of the smallest particle specified. The settling velocity of a particle in a liquid is a function of the specific gravity and viscosity of the liquid and the specific gravity, size, shape, and possibly concentration of the particles. The sedimentation basin can be rectangular or circular in shape with the fluid flow being either horizontal or vertical. A term generally used in the design of sedimentation basins is called the loading rate or flow rate per unit of surface area (Q/A). The average value for loading rate is between 600 and 1,200 gallons per day per square foot of sedimentation surface area, and the outlet weir loading rate usually is set at 30,000 gallons per day per foot of weir length.[28] Experience has shown that these rates ensure an even distribution throughout the basin if it is properly designed to prevent fluid short circuiting (fluid flow directly from inlet to outlet with no settling time).

Chemicals called coagulants are often added prior to sedimentation to speed up and increase the efficiency of the process. This allows for smaller sedimentation basins and lower initial cost. Coagulation consists of feeding the chemicals, followed by a rapid mix of about 2 minutes, and then by a slow mix called flocculation for about 30 minutes. The chemicals or coagulants used are aluminum sulfate (alum), ferrous sulfate, ferric sulfate, ferric chloride, sodium aluminate, and polyelectrolytes. Coagulation is designed mainly to remove minute, suspended particles called colloids in the size range of 1 to 200 microns. Colloids are essentially nonsettleable because of their small size and cannot be removed by plain sedimentation.

Colloids may be both organic and inorganic. The colloids of particular interest in a treatment system are compounds of iron such as ferric hydroxide. The addition of coagulants in the rapid mix phase involves the neutralization of the predominantly negatively-charged colloids by adding an excess of positively charged particles. These are usually hydrous oxide colloids formed by the reaction of the coagulant with ions in the water. The hydrous oxide particles form flocs which attract the negative colloids. During the flocculation or slow-mix phase, the fine floc particles are collected into larger floc particles that can settle out more rapidly. Slow mixing must be done at very low fluid velocities to prevent physically breaking the floc particles.

The various coagulants will only operate effectively within certain pH ranges. The pH range for alum is 5.5 to 8.0, with 6.0 to 7.0 being optimal. Hydrated lime is usually added to adjust the pH to this range. Other chemical additions may include compounds called coagulation aids which are sometimes used in conjunction with the basic coagulating chemicals. Coagulation aids include such compounds as activated silica and polyelectrolytes which aid in the formation of larger, stronger, and denser flocs.

Centrifugal separators (desanders) have also been used to supplement gravity separation in the removal of solids from injection water.[28]

FILTRATION

Filtration is a treatment process usually included in both closed and open systems. In closed systems it is the primary means of removing suspended solids, whereas in open systems it is used to remove floc particles that were not removed in the sedimentation process. The most common types of filters used in brine disposal systems are the slow sand filter and the rapid sand filter.

Slow Sand Filters

Slow sand filters are composed of sand bedding with the top layer of sand used as the filtering media. A disadvantage of this type of mechanism is that the sand bedding material cannot be back-washed or cleaned; rather it must be removed and replaced after clogging.

Wright[30] indicates that the slow sand filter has been superseded by the rapid sand filter in all new installations built in recent years because slow sand filters are relatively inflexible and require too much surface area.

Rapid Sand Filters

Rapid sand filters are classified as gravity sand filters or pressure sand filters. The gravity filter is usually open to the atmosphere, whereas the pressure filter is enclosed in vessels and operated at elevated pressures which can increase the flow rate and prolong the filter cycle. Gravity filters are usually operated at a rate of 2 gallons per minute (gpm) per square foot of filter surface area, whereas pressure filters may be operated at 3 gpm per square foot.[42] Rapid sand filters usually have a layer of sand on layers of graded gravel; however, in some instances, coal (e.g., "anthrafil") has been used in place of the sand, or as another layer on top of the sand. Filtration does not occur on the top layer of a rapid filter as it does in a slow filter. Instead, the particulate matter is adsorbed on the sand at different depths.

The filter media must be periodically back-washed to remove the filtered sediment. This means that when the pressure drop through a filter exceeds a certain value it is taken off line for backwashing. The reverse flow of water up through the filter media must expand the bed on the order of 30 to 50 percent of its normal depth to provide enough permeability for the wash water to thoroughly remove entrapped sediment. The back-wash rate is in the order of 12 to 15 gallons per square foot of filter surface area per minute and is applied for about 5 minutes.[42] The backwash cycle stratifies the sand, arranging the fine sand on top and the coarse material on the bottom of the filter bed (see Figure 8).

The theory and design of filters, as well as the other unit operations involved in water treatment, are fairly complicated to design and operate; however, these procedures are well documented.[42]

In some disposal applications, proper brine water treatment can be the most difficult phase of the entire operation, as well as the most expensive. The prospective operator is advised to refer to Introduction to Oilfield Water Technology[39] and Water Problems in Oil Production, An Operator's Manual[18] for a more complete presentation of brine water treatment.

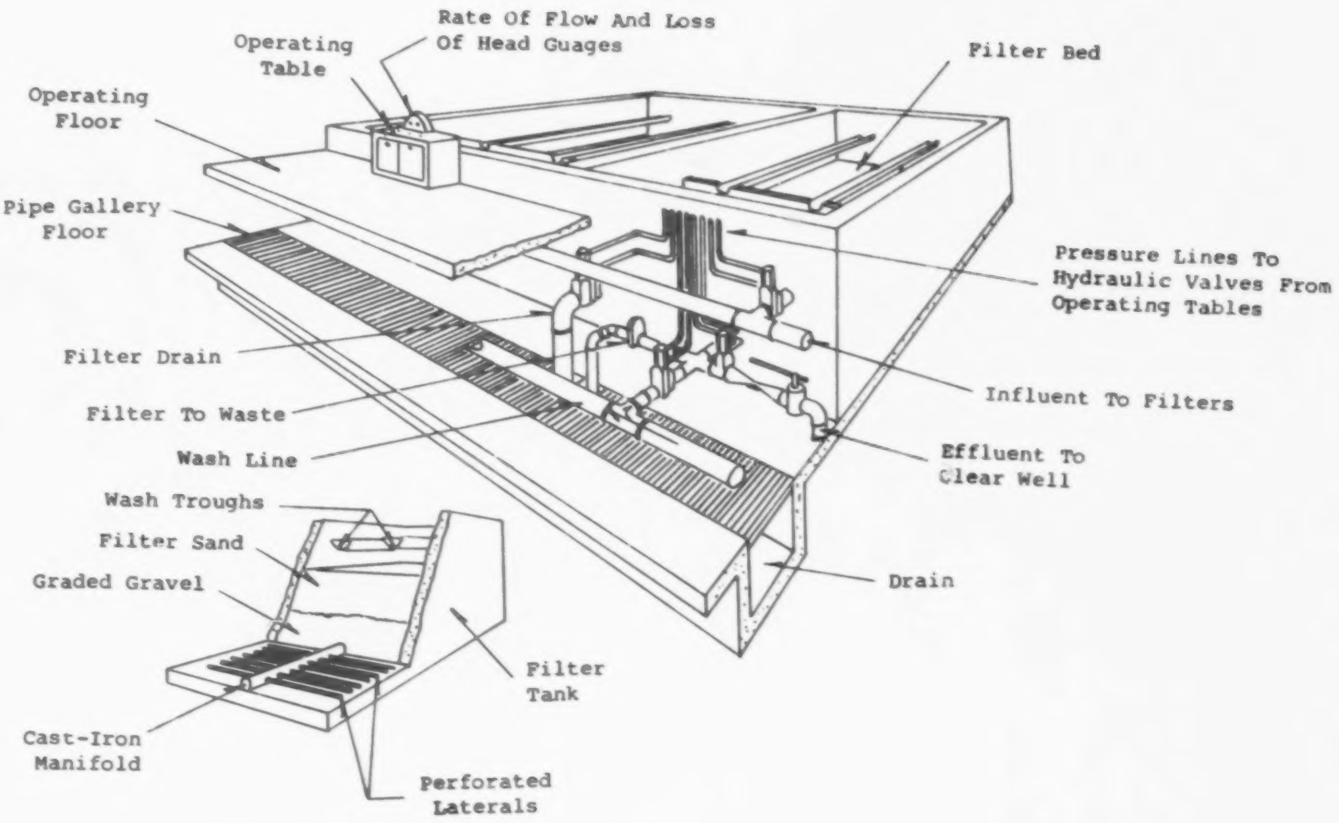

Rate Of Flow And Loss Of Head Guages
Operating Table
Operating Floor
Filter Bed
Pipe Gallery Floor
Pressure Lines To Hydraulic Valves From Operating Tables
Filter Drain
Influent To Filters
Filter To Waste
Wash Line
Effluent To Clear Well
Wash Troughs
Filter Sand
Graded Gravel
Drain
Filter Tank
Cast-Iron Manifold
Perforated Laterals

Figure 8. Rapid Filter and Accessory Equipment.[42]

SECTION V

ANALYSIS OF DISPOSAL ALTERNATIVES

At this point the prospective brine disposal mechanism operator should begin to consider his own disposal needs. In this regard, the assumption is that he will have to answer two basic questions:[43]

1. What type of disposal system do I need?
2. How much will it cost me to construct and operate an appropriate disposal system on an annual basis?

The answer to the first question is provided, basically, by the specifications of the oil regulating agency in each state, as well as the physical considerations of each system. Specific design arrays of brine disposal systems have been developed for desalinization processes in other publications[16, 17] and are useful for oilfield brine considerations. These arrays will be presented, after conversion to appropriate terminology, in this section.

An effort has been made to present these analytical methods in a logically consistent manner, supplemented by clarifying instructions, to result ultimately in a realistic, easy to follow procedure. In addition, a computer program (Appendix E) has been prepared for calculating general configuration designs and costs of new construction within the basic design configurations. The derivations of formulaic relationships used in these analyses are developed in Appendix D. Along with each calculation are the necessary terminology and explanations to complete the cost analyses.

ANALYSIS FOR DIRECT DISCHARGE OR CONVEYANCE

Basically, this analysis develops the design configuration of pure water flowing in a pipeline from the point of brine collection to the direct discharge site (or to the brine water treatment plant, if this operation is necessary). In function, the supply pipeline and pumping analysis is that of simple fluid transport and remains the same whether used to transport the brine to the direct discharge site, evaporation pond or pit, injection site, or to another piece of equipment such as a treatment system or storage tank. Of course, many areas use tank trucks to haul the brine from the production site to the disposal site, where discharge occurs either directly into a disposal mechanism, into a holding tank, or to a small water treatment plant. If trucking is used in place of pipelining, the cost in dollars per barrel will already be known and can be added to disposal mechanism cost in determining total and annual disposal costs.

DIRECT DISCHARGE ANALYSIS

The following information is required before beginning the analysis:

1. Quantity of brine to be disposed of in gallons (42 gallons per barrel) per day (X_B): ______gpd
2. Quantity of oil in gallons per day produced with brine (X_o): ______gpd
3. Number of years of project (Y): ______years
4. Company's discount rate (i): ______decimal fraction
5. Length of pipeline in miles from brine collection point to discharge point (F'): ______miles
6. Discharge elevation in feet above (-) or below (+) brine collection point (EL): ______ft
7. Cost of right-of-way (assume a 30-foot wide strip at a land cost of $109/acre--unless better cost can be obtained) (ROW): ______$

8. Cost of pipe per foot (CPU): ______\$/ft

9. Cost of lining pipe with cement, per foot (CCU): ______\$/ft

10. Cost of pipe installation per foot: ______\$/ft

11. Cost per kilowatt hour of electricity (ECU): ______\$/KWH

12. Current year Engineering News Record Building Cost Index (ENRBCI): ______decimal fraction

13. State specifications for design.

DIRECT DISCHARGE CALCULATIONS[53]

1. If the pipe requires a cement liner, calculate the inside diameter required for the liner (I.D.), assuming a liner thickness of .25 inch:

   $\text{I.D.} = (X_B^{.45})(.017) + .50$ ______I.D., inches

   if no liner:

   $\text{I.D.} = (X_B^{.45})(.017)$

2. Enter O.D. corresponding to the cement liner:

   $\text{O.D.} = (1.07)(\text{I.D.}) = \text{I.D.} + 1/2$ inch ______O.D., inches

3. Enter weight per foot (total) of pipe: ______lb/ft

4. Enter yield pressure of pipe used (P_s): ______psi

5. Calculate head loss due to friction (H_f) for water flowing through a cement-lined pipe:

   $H_f = (.003)(5{,}280)(F')$ ______ft

6. Calculate the required pumphead (H_p):

   $(H_p) = \text{discharge elevation} - H_f$

   $H_p = E - H_f$ ______ft

7. Calculate the required pump discharge pressure (which is also the minimum allowable yield pressure for the pipe):

   Pump discharge (P_D) = .434 pumphead (H_p) ______psi

8. If calculated for more than one size of pipe, compare the pipe yield pressure (P_s) with the calculated yield pressure (P_D) and select least expensive pipe whose yield pressure (spec) $\geq P_D$

9. Pump requirement? ______yes ______no

(A pump will be required if H_p is (-).)

10. Pump power requirements:

a. Hydraulic horsepower = HHP

$$\text{HHP} = \frac{(X_B)\ (P_D)}{(2.468)\ (1,000,000)}$$ ______HHP

b. Brake horsepower = BHP

$$\text{BHP} = \frac{\text{Hydraulic horsepower}}{\text{Pump efficiency}}$$ ______BHP

(Assume pump efficiency = .85 if not stated.)

c. Kilowatt hours = KWH

$$\text{KWH} = \frac{(\text{Brake horsepower})\ (.7457)}{\text{Motor efficiency}}$$ ______KWH

(Assume motor efficiency = .93 if not stated.)

11. Calculate pump capacity:

$$\text{Pump capacity} = \text{gpm} = \frac{X_B}{1440}$$ ______gpm

DATA SUMMARY

1. Supply pipeline and pump:

a. Length of line ______F, feet

b. Pipe size (cement-lined): ______I.D., inches

c. Pipe size (cement-lined): ______O.D., inches

d. Pump required: ______yes ______no

2. Pump power requirements

   a. brake horsepower: ______BHP

   b. kilowatts: ______KWH

COST PROCEDURE FOR DIRECT DISCHARGE

1. Cost of pipe:

   a. Cost per foot (CPU): ______\$/ft.

   b. Cost of Pipeline (CP) = (F) (CPU): ______\$

2. Cost of cement lining (see Figure 9):

   a. Cost of cement lining per foot (CCU): ______\$/ft.

   b. Cost of lined pipe (CC) = (F) (CCU): ______\$

3. Subtotal (ST_1):

   $ST_1 = [CP + CC]\ F$ ______\$

4. Construction cost subtotal (ST_2):

   a. Piping installation cost (CI) = (F) (\$/foot installed) ______\$

   b. Cost of right-of-way (ROW):

      Cost of right-of-way=(ROW) = (F) (\$/foot right-of-way) ______\$

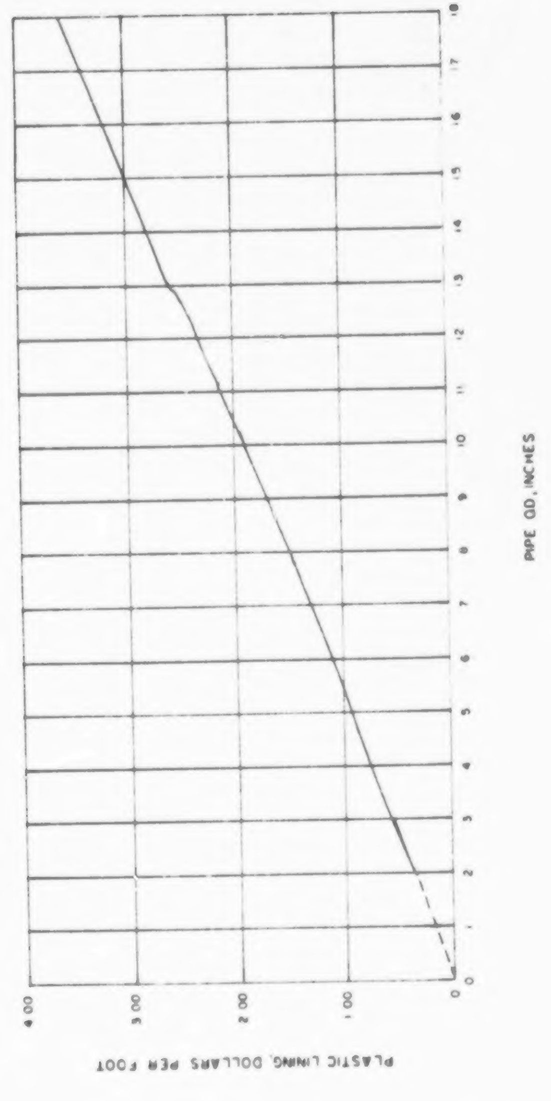
5. Pipeline Construction cost (ST_2):

   $ST_2 = ST_1 + [CI + ROW]\ F$ ______\$

SUPPLY LINE COST

1. Capital cost:

   a. Cost of pipeline (ST_2) ______\$



Note: Data used in the preparation of this graph was obtained in 1962 (Engineering News Record Building Cost Index, ENRBCI, of 570). To update to current year, multiply graph values by (ENRBCI of current year/570).

Figure 9. Cost of Plastic or Cement Lining of Pipe in Dollars per Foot Versus Outside Diameter of Pipe in Inches.[47]

b. Contingencies (.10) (ST_2):

(Assume 10% of pipeline cost.) ______\$

c. Engineering (.10) (ST_2 + contingencies):

(Assume 10% of pipeline and contingencies cost.) ______\$

d. Interest on construction (i_c):

(Assume 1.625% of cumulative capital costs.)

i_c = (.01625) (ST_2 + contingencies + engineering) ______\$

e. Capital cost (CC_p):

$CC_p = ST_2$ + contingencies + engineering + i_c ______\$

2. Annual expenditure (\$/yr):

a. Annual amortized expenditure (A_p):

$A_p = (CC_p) \left[\frac{i\ (1+i)^Y}{(1+i)^Y - 1} \right]$ ______\$/yr.

b. Operation, Maintenance, and Supplies (O_p):

(Assume .25% of capital cost.)

$O_p = (.0025)\ (CC_p)$ ______\$/yr.

c. Interest on working capital (i_{wc}):

(Assume .7% of all annual expenditures.)

$i_{wc} = (.007)\ (A_p + O_p)$ ______\$/yr.

d. Total annual expenditure = TAE_p:

$TAE_p = A_p + O_p + i_{wc}$ ______\$/yr.

PUMP STATION COST

1. Capital cost (knowing brakehorsepower, determine cost of pump and motor; see Figure 10).

   a. Cost of pump (P_{cu}): ______$

   b. Contingencies (.10) (P_{cu}):
   (Assume 10% of pump cost) ______$

   c. Engineering (.10) (P_{cu} + contingencies):
   (Assume 10% of pump cost and engineering) ______$

   d. Interest on construction (i_c):
   (Assume 1.625% of cumulative capital costs.)
   i_c = (.01625) (P_{cu} + contingencies + engineering) ______$

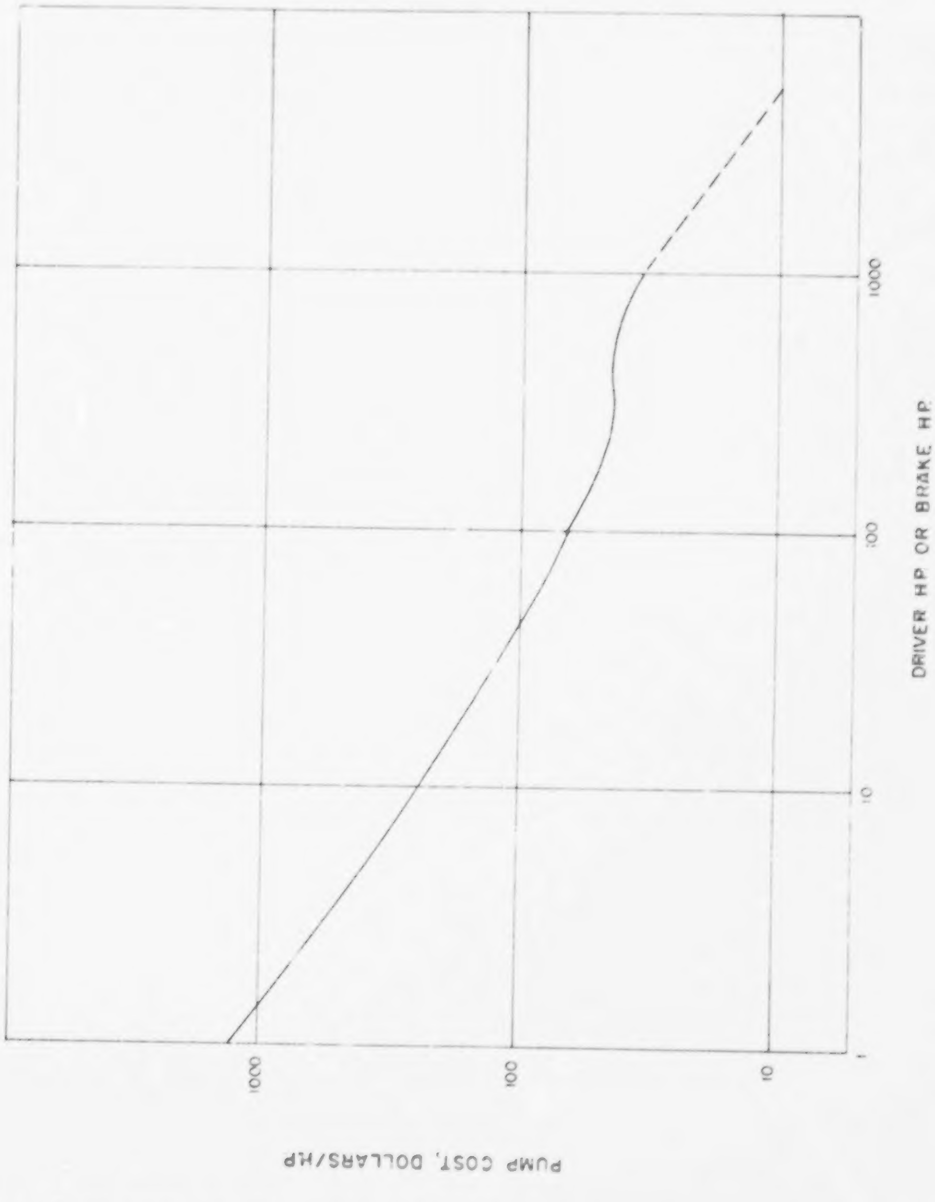
   e. Capital cost (CC_{PS}):
   $CC_{PS} = P_{cu}$ + (contingencies + engineering + i_c) ______$

2. Annual expenditure ($/yr):

   a. Annual amortized expenditure (A_{PS}):
   $A_{PS} = (CC_{PS}) \left[\frac{i(1+i)^Y}{(1+i)^Y-1}\right]$ ______$

   b. Materials and supplies (M_{PS}):
   (Assume .25% of capital cost.)
   $M_{PS} = (.0025)\ CC_{PS}$ ______$/yr.

   c. Power cost (EC):
   EC = (KWH) (ECU) 8760 hr/yr ______$/yr



Note: Data used in the preparation of this graph was obtained in 1962 (Engineering News Record Building Cost Index, ENRBCI, of 570). To update to current year, multiply graph values by (ENRBCI of current year/570).

Figure 10. Cost of Installed Centrifugal Pump and Motor in Dollars per Horsepower Versus Brake Horsepower.[47]

d. Operations and maintenance (OM):

(Obtain estimate from curve in Figure 11.) ______$/yr

e. Payroll overhead (PO = (.15) (OM):

(Assume 15% of operations and maintenance cost.) ______$/yr

f. General and administrative (GA):

(Assume 30% of operation and maintenance, and payroll overhead cost.)

$GA = (OM + PO)\ (.30)$ ______$/yr

g. Interest on working capital (i_{wc}):

(Assume .7% of other annual costs.)

$i_{wc} = (.007)\ (A_{PS} + M_{PS} + EC + OM + PO + GA)$ ______$/yr

h. Total annual expenditure (TAE_{PS}):

$TAE_{PS} = A_{PS} + M_{PS} + EC + OM + PO + GA + i_{wc}$ ______$/yr

3. Total unit cost of supply pipeline and pumping per barrel of oil (TUC_{OPPS}):

$$TUC_{OPPS} = \frac{(TAE_P + TAE_{PS})\ (42)}{(X_o)\ (365.)}$$ ______$/brl oil

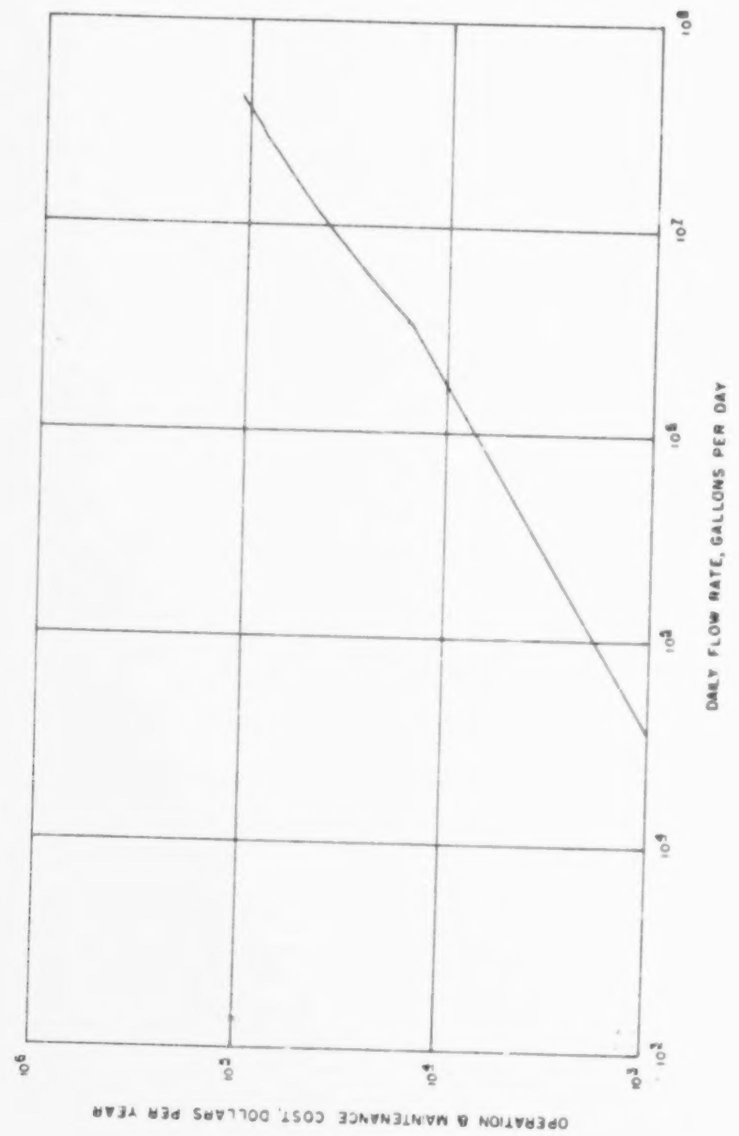
4. Total unit costs of supply pipeline and pumping per barrel of brine handled (TUC_{BPPS}):

$$TUC_{BPPS} = \frac{(TAE_P + TAE_{PS})\ (42)}{(X_B)\ (365.)}$$ ______$/brl brine

TOTAL DIRECT DISCHARGE SYSTEM COST (Pipeline + Pumping)

1. Total capital cost (TCC_{PPS}):

$TCC_{PS} = CC_P + CC_{PS}$ ______$



Note: Data used in the preparation of this graph was obtained in 1962 (Engineering News Record Building Cost Index, ENRBCI, of 570). To update to current year, multiply graph values by (ENRBCI of current year/570).

Figure 11. Estimated Operation and Maintenance Cost for Pump Station or Well Field in Dollars per Year Versus Daily Flow Rate in Gallons per Day.[48]

2. Total annual expenditures (TAE_{PPS}).
   $TAE_{PPS} = TAE_P + TAE_{PS}$ ______\$/yr
3. Total unit cost per barrel of oil produced
   (TUC_{OPPS}): ______\$/bbl oil
4. Total unit cost per barrel of brine handled
   (TUC_{BPPS}): ______\$/bbl brine

ANALYSIS FOR EVAPORATION POND OR PIT

This analysis considers only the design configuration and associated approximate costs necessary to develop an appropriate evaporation pond (see Figure 3). The evaporation unit is assumed to be installed at the discharge end of the pipeline previously developed in the direct discharge analysis; i.e., the complete evaporation system would involve both the direct discharge analysis from the point of brine collection to the inlet of the evaporation pond and the analysis for the evaporation pond. From a cost point of view, this means that the total evaporation system cost equals the sum of the costs associated with the pipeline and pumping, those associated with the evaporation pond, and those associated with storage units which might be needed.

EVAPORATION POND

Assuming the brine is piped to the evaporation site, the following information is required before beginning the analysis. From pipeline and pump (Direct Discharge):

1. Total capital cost (CC_{PPS}): ______\$
2. Total annual expenditure (TAE_{PPS}): ______\$
3. Total unit cost per barrel of brine handled (TUC_{BPPS}): ______\$/brl brine
4. Total unit cost per barrel of oil produced (TUC_{OPPS}): ______\$/brl oil

The following information will also be used in the analysis.

1. Average quantity of brine in gallons per day to be disposed of (X_B): ______gpd
2. Total dissolved solids in brine (Q_B): ______ppm_{TDS}
3. Quantity of oil in gallons per day produced with the brine (X_O): ______gpd
4. Number of years of project (Y): ______yrs
5. Campany's average cost of capital or discount rate (i): ______(decimal fraction)
6. Land cost (CLU): ______\$/acre
7. Cost of electricity per kilowatt hour (ECU): ______\$/KWH
8. Net evaporation rate (NER) (See disposal pond section for evaporation rate calculation methods.) ______in./day
9. 24-hour point rainfall depth for 50-year recurrence (storm) interval: ______ft.
10. Liner cost installed if liner used (or assume \$.031/ft^2): ______\$/ft^2

11. Cost of clearing land (or assume \$100/acre): ______\$/acre
12. Cost of liner fill if liner used (or assume \$.40/yd^3): ______\$/yd^3
13. Cost of excavating dike (or assume \$1.00/yd^3): ______\$/yd^3
14. Current year *Engineering News Record Building Cost Index* (ENRBCI): ______
15. State specifications for design.

EVAPORATION POND ANALYSIS

1. The actual number (or fraction) of acres required for the pond depends on the evaporation rate, depth of brine to be maintained in the pond (combined with the flow rate of the incoming brine), and the general amount of land available either due to physical or economic limitations. In effect, there is a balance between capacity and land area, with overriding topographic considerations. In addition, the average daily amount of brine flowing into the pond (X_B) is assumed to be constant and containing insufficient oil to form an evaporation-retarding film on the surface of the pond. (As little as 1/2 pint of oil forms a film on an evaporation pond with a surface area of one acre.)

$$SA = \text{Surface area required (acres)} = \frac{X_B}{{}^{*}NER\ (2.72 \times 10^4)}$$

*It should be pointed out that the net evaporation rate (NER) should be adjusted for brine salinity as indicated in the earlier section on evaporation.

Although the recommended average evaporation pond liquid depth is 1 to 1.5 feet, the operator may want to increase the liquid depth capacity to accommodate peak quantities of brine and rainfall and to provide for extended periods of humid weather and low wind velocity. Thus, he may actually maintain the 1 to 1.5 foot level but increase the liquid depth capacity to 2 feet or even 4 feet.

Design pond brine liquid depth capacity ______ feet

2. Another factor to consider is that as the water is evaporated from the brine, the suspended and dissolved materials accumulate at the bottom of the pond as a residue. The depth of this accumulated residue may be obtained in the following manner.

First, having obtained the brine salinity by chemical analysis, locate the decimal fraction of deposit per foot of brine depth per year corresponding to the salinity of the inflowing brine from Figure 12. Next, knowing the inflow volume of brine in barrels per day, (X_B), and the surface area of the evaporation pond in acres, locate the depth of brine solution per year from Figure 13. This depth, when multiplied by the decimal fraction of residue per foot of brine previously determined, gives the number of feet of residue which can be expected to accumulate each year in the evaporation pond. Assuming that the brine flow rate and salinity remain constant over the life of the evaporation pond, multiply the project life, in years, by the number of feet per year of residue

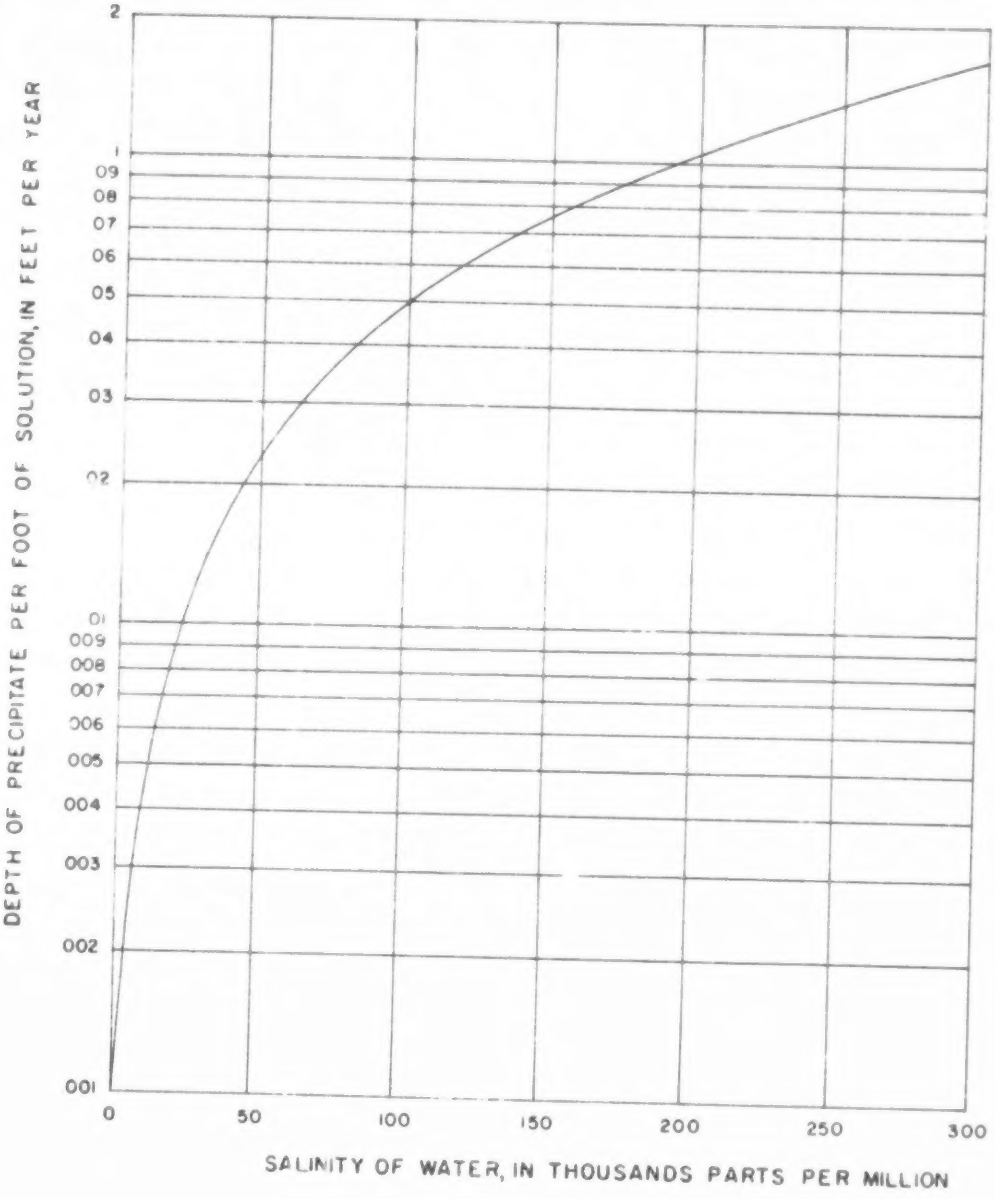


Figure 12. Depth of Precipitate per Foot of Solution in Feet per Year Versus Salinity of Water in Thousands of Parts per Million.[49]

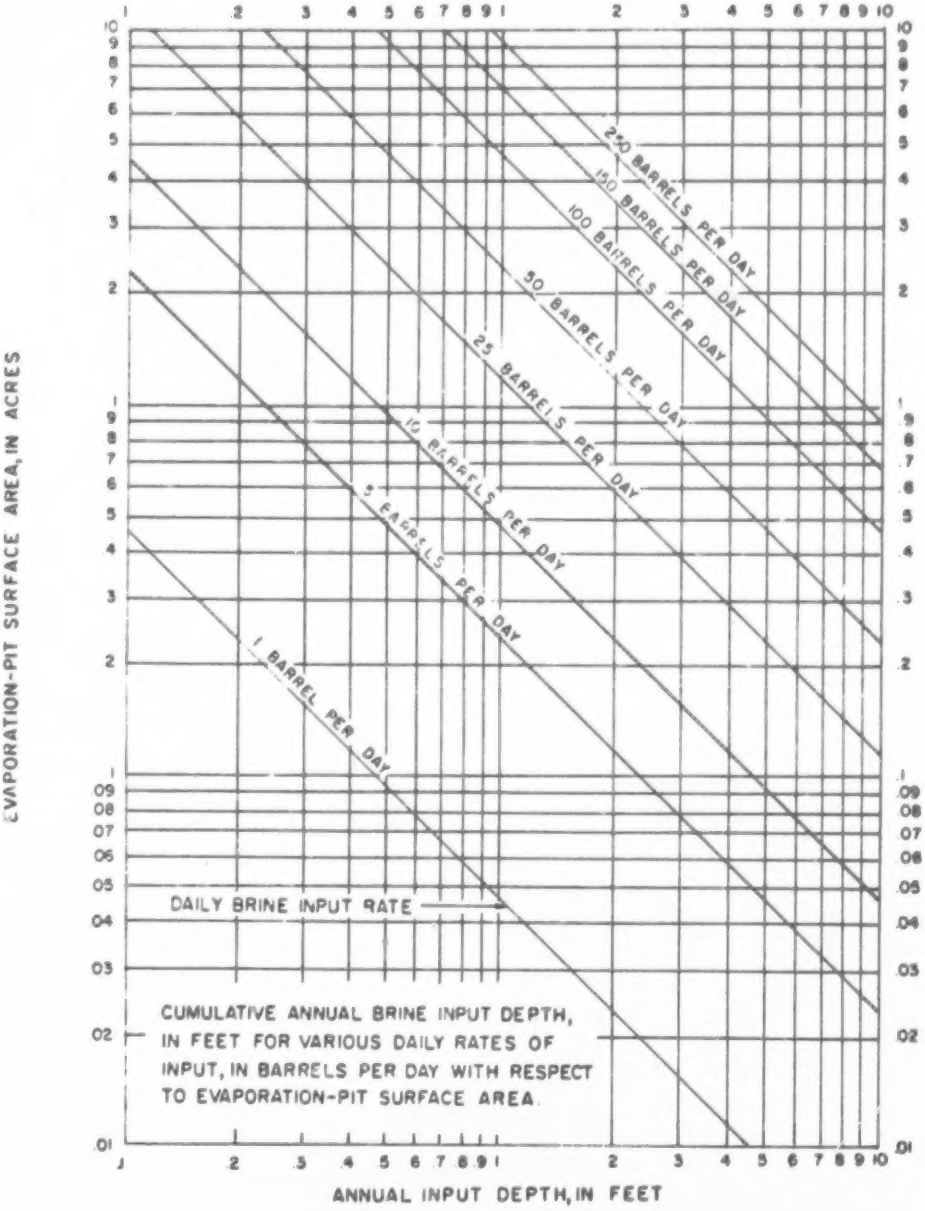


Figure 13. Evaporation Pond Surface Area in Acres Versus Annual Input Depth in Feet for Determining the Depth of Precipitate Deposited in One Year for Various Daily Rates of Input.[24]

accumulation. This value is the expected total residue build-up over the life of the project.

Total residue ______feet

3. Next, determine the 24-hour maximum point rainfall depth for a recurrence interval of 50 years (storm) from the weather bureau for the vicinity of the evaporation pond.

Maximum rainfall ______feet

4. Assume a freeboard of 2 feet. This value is good up to an 80 miles per hour wind blowing over a pond with a downwind length of 2,000 feet.

Total freeboard 2 feet

5. Assume a 1-foot soil cover over the pond liner (if not surrounded by impervious soil).

Soil cover 1 feet

6. The total pond depth, measured from the bottom of the pond to the top of the dike, is the sum of these depths (Dike height, H):

Liquid capacity ______feet
Total Residue ______feet
Maximum rainfall in a 24-hour, 50-year storm ______feet
Total freeboard ______feet
Soil cover over liner ______feet

Total pond depth (H) ______feet

Note: The dike is assumed to have 4-foot crest with a 2:1 slope on the toe and a 3:1 slope on the heel.

7. The next step is to determine the length of the dike necessary to enclose the pond. To obtain this value, add the lengths of the sides of the pond; i.e., the perimeter (EP).

Total pond perimeter (EP) ______yards

8. From Figure 14, determine the volume of dike material, in cubic yards, required per linear yard of dike. Normally, material for dikes is obtained from pond excavation materials.) For example, a pond with a dike height of 10 feet would require 32 cubic yards of material per yard of dike length.

Total volume of dike material (VT) ______yds^3

9. Next, determine the amount (square feet) of liner material (ALA) required. (Omit this step if the soil is impervious and a liner is not required by the state.)

$$\text{ALA} = \text{Area of liner required} = \frac{(.0111\ \text{SA}+6)(\text{H}-5) + (1.0111)(\text{SA})}{(10)}$$

______ft^2

10. Finally, calculate the quantity of fill (VF) necessary to cover the liner with one foot of cover.

$$\text{VF} = \text{Cover fill} = \frac{(35\ \text{SA}+15{,}000)(\text{H}-5)}{10} + (1625)(\text{SA}) + 5{,}000$$

DATA SUMMARY

1. Evaporation area (SA): ______acres
2. Dike height (H): ______feet
3. Length of dike (EP): ______yards
4. Volume of dike material (VT): ______yds^3

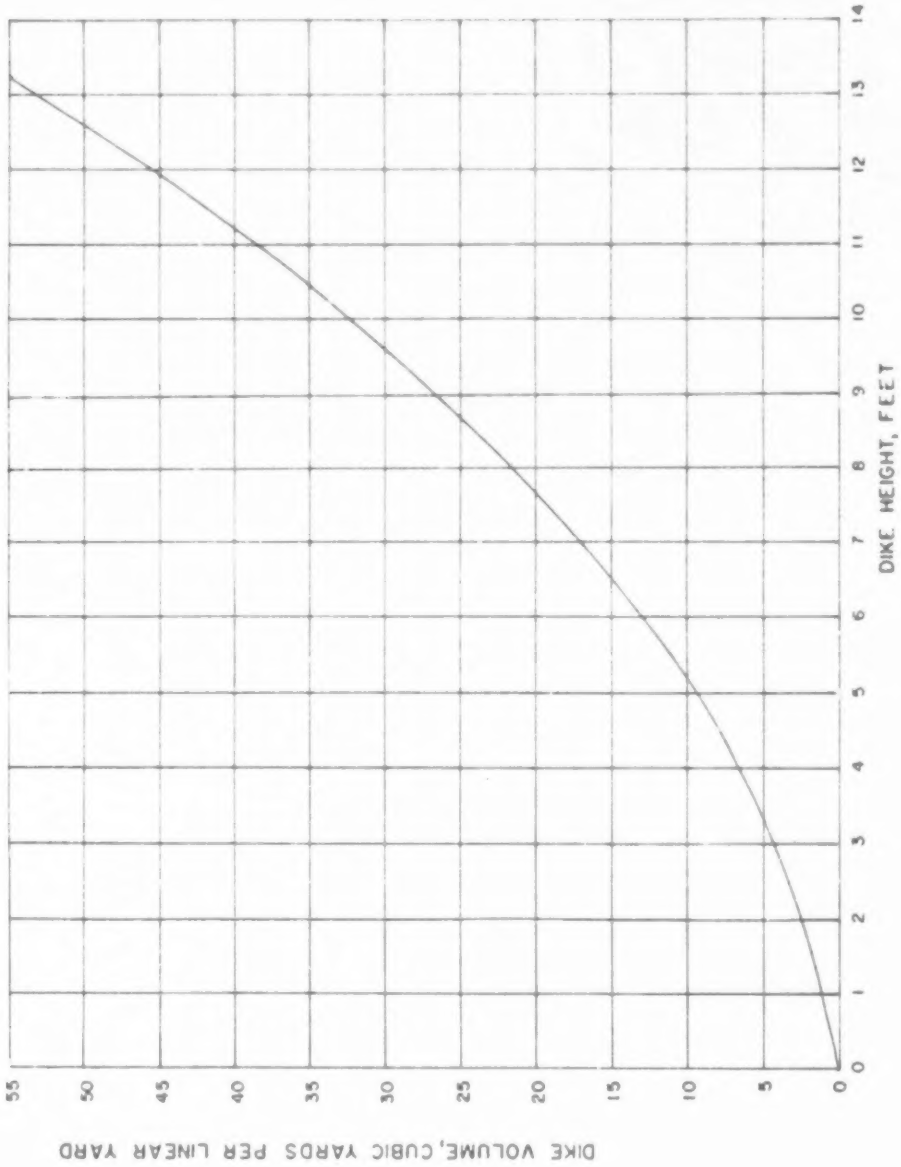


Figure 14. Dike Volume in Cubic Yards per Linear Yard Versus Dike Height in Feet.[49]

5. Liner area (ALA): ______ft^2

6. Volume of liner fill (VF): ______yds^3

EVAPORATION POND SYSTEM COST ANALYSIS

1. Land Cost (LC) = (cost per acre)(number of acres): ______$

2. Cost of stripping the land (CS):
   (Assume $100 per acre.)
   CS = ($100)(number of acres) ______$

3. Liner cost (CLL)--omit if necessary:
   (Assume $.031 per ft^2; ALA = liner area)
   CLL = (ALA)(.031) ______$

4. Cost of liner cover fill (CF):
   (Assume $.40 per cubic yard for labor, material, and equipment.)
   CF = (VF)($.40) ______$

5. Dike cost (CD):
   (Assume $1.00 per cubic yard for labor, material, and equipment.)
   CD = (VT)($1.00) ______$

6. Subtotal, evaporation pond cost (ST_E):
   ST_E = LC + CS + CLL + CF + CO ______$

7. Capital costs:
   a. Evaporation pond cost (ST_E): ______$

b. Contingencies (CE): $(ST_E)(.10)$

(Assume 10% of pond cost.) ______$

c. Engineering (E_E): $(E_E)(.10)(ST_E + C_E)$

(Assume 10% of pond cost and contingencies) ______$

d. Interest on construction (I_{CE}) :

$$I_{CE} = (.01625)(ST_E + C_E + E_E)$$

(Assume 1.625% of cumulative capital costs.) ______$

e. Capital cost (CC_E):

$$CC_E = ST_E + C_E + E_E + I_{CE}$$ ______$

8. Annual expenditure:

a. Amortization expense (A_E):

$$A_E = CC_E \quad \frac{i(1+i)^Y}{(1+i)^{Y-1}}$$ ______$/year

b. Operation and maintenance (OM_E):

(Assume .5% of capital cost.)

$$OM_E = (.005)(CC_E)$$ ______$/year

c. Payroll overhead (PO_E):

(Assume 15% of operation and maintenance.)

$$PO_E = (.15)(OM_E)$$ ______$/year

d. General and administrative (GA_E):

(Assume 30% of operation and maintenance, and payroll overhead.)

$$GA_E = (.30)(OM_E + PO_E)$$ ______$/year

e. Interest on working capital (I_{WE}):

(Assume .7% of all annual expenditures.)

$$I_{WE} = (.007)(GA_E + PO_E + OM_E + A_E)$$ ______$/year

f. Total annual expenditure (TAE_E):

$$TAE_E = (I_{WE} + GA_E + PO_E + OM_E + A_E)$$ ______\$/year

9. Total unit cost of evaporation pond per barrel of oil (TUC_{OE}):

$$TUC_{OE} = \frac{TAE_E\ (42)}{(X_o)(365.)}$$ ______\$/brl oil

10. Total unit cost of evaporation pond per barrel of brine (TUC_{BE}):

$$TUC_{BE} = \frac{TAE_E\ (42)}{(X_B)(365.)}$$ ______\$/brl oil

TOTAL EVAPORATION SYSTEM COSTS (Evaporation Pond + Pipeline + Pump)

1. Total capital cost (TCC_{ES}):

$$TCC_{ES} = CC_E + CC_P + CC_{PS}$$ ______\$

2. Total annual cost (TAE_{ES}):

$$TAE_{ES} = TAE_E + TAE_P + TAE_{PS}$$ ______\$/year

3. Total unit expense per barrel of oil produced (TUC_{OES}):

$$TUC_{OES} = TUC_{OE} + TUC_{OPPS}$$ ______\$/brl oil

4. Total unit expense per barrel of brine disposed (TUC_{BES}):

$$TUC_{BES} = TUC_{BE} + TUC_{BPPS}$$ ______\$/brl brine

INJECTION

The question of what to do with the brine produced with oil is often conveniently answered by secondary recovery of oil. That is, from a pollution point of view, the use of brine as a secondary recovery fluid represents disposal. However, due to treatment costs which may be necessary to prepare the brine for injection into a production strata, a separate, non-productive strata is often selected for brine disposal.

The two basic options in subsurface disposal are to drill a new well or to convert an old well. The following analysis may be used for either case. As in previous analyses, basic values are assumed to simplify the analysis procedure. If better values are obtainable, they should be substituted for the assumed values in the cost or design configuration analysis.

Basically, an injection disposal system is a combination of some type of brine handling device, a treatment plant, and an injection well. The brine handling device consists of either trucking or pipeline and pumping (discussion presented in the Direct Discharge Analysis at the beginning of this section). To the capital and/or annual costs of brine handling must be added the costs of storage facilities (if used), treatment facilities (if used), distribution piping and pumping, and the injection well.

Put rather simply, the injection process is one of moving a fluid (brine or other injection liquid) down a vertical tube and then dispersing the fluid within a porous reservoir formation. Thus, the design analysis of an injection well involves fluid and reservoir mechanics.

The injected fluid encounters a fluid friction force with the walls of the tubing and exerts a static pressure head (height-force) which is essentially the weight of the column of fluid in the tubing. The static pressure head aids injection; however, the fluid friction force along with the pressure of fluid already in the formation resists injection. The amount of resistance to flow depends on such factors as the inside diameter of the injection tube (the smaller the diameter, the greater the friction force on the fluid), the amount of flow, and the viscosity of the brine. In the reservoir, resistance to flow is influenced by the depth, thickness, porosity, and permeability of the formation. The calculations for these factors are given in Appendix D.

Assuming the brine is piped to the injection site, the following information is required before beginning the analysis. From pipeline and pump:

1. Total capital cost (CC_{PPS}): ______$
2. Total annual expenditure (TAE_{PPS}): ______$/year
3. Total unit cost per barrel of brine handled (TUC_{BPPS}): ______$/bbl brine
4. Total unit cost per barrel of oil produced (TUC_{OPPS}): ______$/bbl brine

In addition to the information supplied in the conveyance or direct discharge analysis, the following must also be provided:

1. Quantity of brine to be disposed of in gallons (42 gallons per barrel) per day (X_B): ______gpd
2. Quantity of oil in gallons per day produced with brine (X_o): ______gpd
3. Number of years of project life (Y): ______years
4. Company's average cost of capital or discount rate (i): ______decimal fraction
5. Cost of right-of-way (assume a 30-foot wide strip at a land cost of $109/acre unless better cost can be obtained)(ROW): ______$
6. Cost per kilowatt hour of electricity (ECU): ______$/KWH
7. Current year *Engineering News Record Building Cost Index* (ENRBCI): ______
8. Disposal formation lithology requirement (Li) (0 closed hole, 1 open hole): ______
9. Total disposal well depth (L): ______feet
10. Disposal formation porosity (ϕ): ______(decimal fraction)
11. Disposal formation permeability (K): ______Darcy
12. Disposal formation effective height (h): ______feet
13. Disposal formation reservoir pressure (P_r): ______psi
14. State specifications for design.

DESIGN LIMITATIONS ON CASING AND TUBING

1. Set surface casing thru base of fresh water sand (D_{sc}): ______feet

2. Maximum casing head pressure (P_{ch}):

$P_{ch} = .5(L)$ ______psi

3. Minimum tubing I.D. = 2 inches (to prevent excessive friction)

INJECTION WELL FIELD DESIGN PROCEDURE

1. Select tubing I.D. (but do not exceed maximum in Figure 15)(d): ______inches
2. O.D. of external upset tubing of I.D.: ______inches
3. Tubing coupling O.D.: ______inches
4. Minimum collapse resistance of production casing = 2L (note: 2 psi/ft depth): ______psi
5. Production casing I.D. equal tubing coupling O.D. plus 2 inches minimum (check collapse resistance; must be equal to or greater than minimum): ______inches
6. Production casing O.D.: ______inches
7. Production casing coupling O.D.: ______inches
8. Bottom hole diameter (production hole diameter), equal to production casing coupling O.D. plus 2 inches: ______inches

FLUID MECHANICS (See Appendix D for Derivations)

1. Well radius (R_w) = 1/24 (bottom hole diameter): ______inches
2. Well diameter = Tubing I.D. = d ______inches

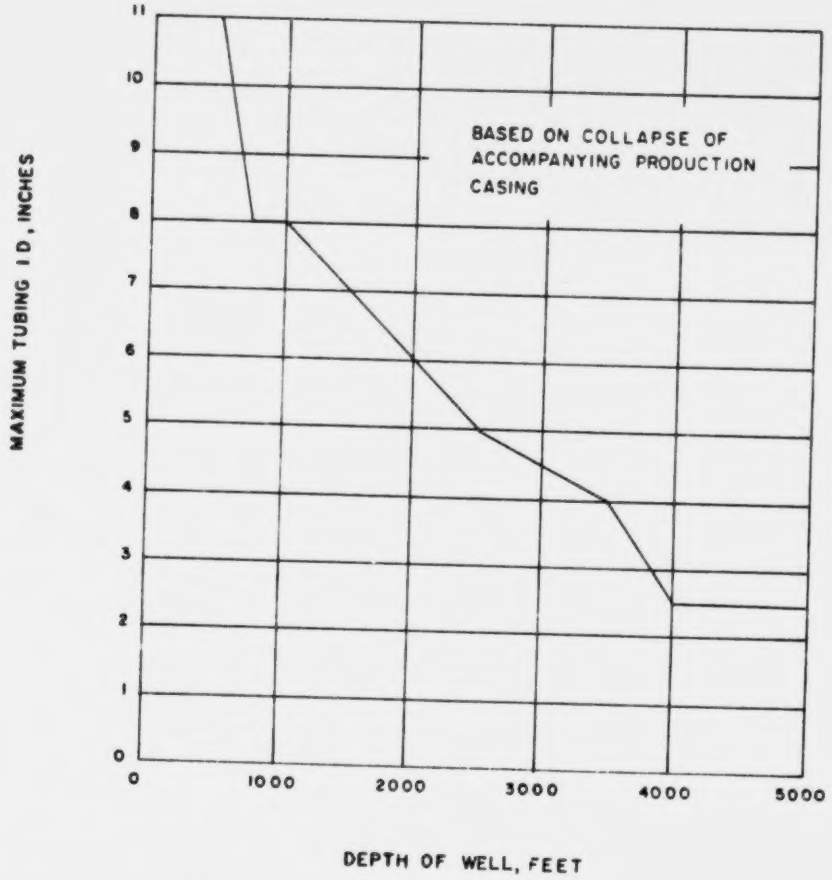


Figure 15. Maximum Tubing Inside Diameter in Inches Versus Depth of Well in Feet.[50]

3. Number of injection wells (N) (usually 1): ______

4. Flow rate per well = $X_{Bi} = \frac{X_B}{N}$ ______gpd

5. Velocity of injected fluid (V):

$$V = (2.84)\ (10^{-4})\ \frac{X_{Bi}}{d^2}$$ ______ft/sec

6. Reynolds Number (N_{RE}):

$$N_{RE} = (7.75)\ (10^3)\ (d)\ (V)$$ ______

7. Enter friction factor (f) from Figure 16

(use N_{RE}): ______

8. Friction loss (P_f):

$$P_f = (32.36)\ (10^{-2})\ (f)\ (L)\ (V^2)/(d)$$ ______psi

9. Fluid radius at end of project (r_e):

$$r_e = (124.6)\ \left[\frac{(X_{Bi})(Y)}{(1{,}000)(h)(\phi)}\right]$$ ______feet

10. Well spacing ($2\ r_e$): ______feet

11. Bottom hole driving pressure (P_d):

$$P_d = \left[\frac{(X_{Bi})\log\left[\frac{r_e}{r_w}\right]}{(128.9)(k)(h)}\right]$$ ______psi

12. Static fluid pressure (P_c) = .434 (L) ______psi

13. Calculated casing head pressure (P_{ch}):

$$P_{ch} = P_d + P_r + P_f - P_c$$ ______psi

14. Allowable maximum P_{ch} = (1.0)(L): ______psi

Note: If Calculated P_{ch} is greater than allowable limit (1.0)(L), repeat steps 2 through 12 assuming 1 more well each time until P_{ch} is less than or equal to (1.0)(L). Also recheck for design limitations above.

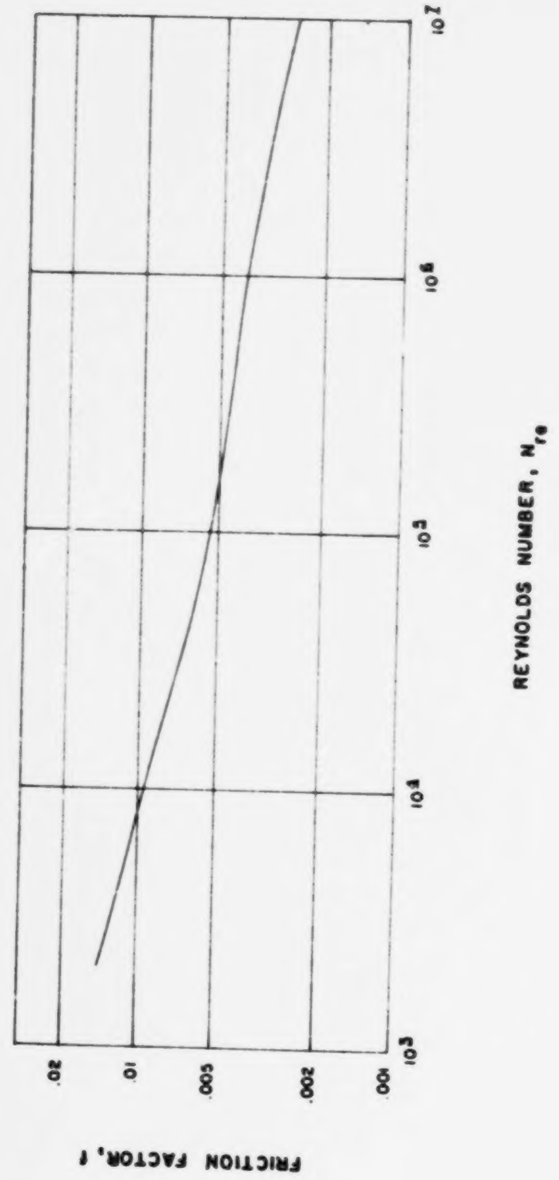
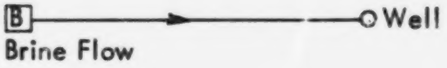


Figure 16. Friction Factor Versus Reynolds Number.[51]

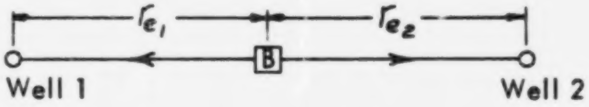
DISTRIBUTION PIPING--CEMENT-LINED

1. Arrange wells around injection pump so that the minimum distance between any two wells is at least (2) (r_e) of the wells.

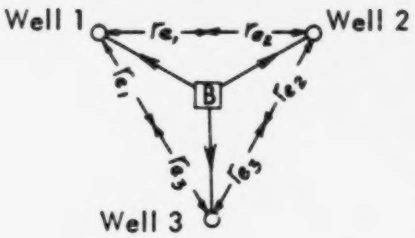
Note: 1 well.


B
Well
Brine Flow

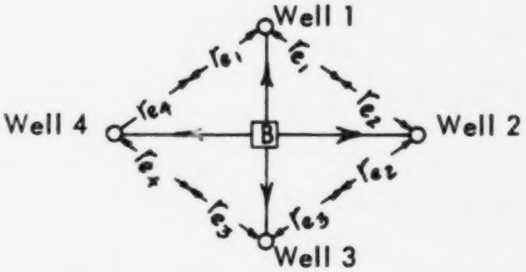
2 wells.


r_{e_1}
r_{e_2}
B
Well 1
Well 2

3 wells


Well 1
Well 2
r_{e_1}
r_{e_2}
r_{e_1}
B
r_{e_2}
r_{e_3}
r_{e_3}
Well 3

4 or more wells on branches.


Well 1
r_{e_1}
r_{e_1}
r_{e_4}
r_{e_2}
Well 4
B
Well 2
r_{e_x}
r_{e_2}
r_{e_3}
r_{e_3}
Well 3

2. Determine the pipe size (d) of the line from the pump to each well:

   d = $(1.7)(10^{-2})(X_{Bi}^{.45})$ where X_{Bi} is the flow of brine in gpd in the line being sized. ______inches

3. Add ½ inch to d for cement lining (d') ______inches

4. Minimum yield pressure from previous section (P_{ch}): ______psi

5. With I.D. = d', consult Yield Pressure Tables: ______psi
Must be equal to or greater than minimum in table (see Halliburton Cementing Tables, Halliburton Company, Duncan, Oklahoma).

6. Complete following table for each distribution pipe:

d	d'=I.D.	O.D.= I.D.+½ in.	lb/ft	Type of pipe
________	________	________	________	________

7. Friction loss in line connection distribution pump and most distant well ($\overline{FL}$) = (.0013)(length,ft): ______psi

INJECTION PUMP AND POWER REQUIREMENTS

1. Injection pump discharge pressure (P_p):

$$P_p = P_{ch} + \overline{FL}$$
______psi

2. Hydraulic horsepower (HHP):

$$HHP = \frac{(X_B)(P_p)}{(2.468)(10^6)}$$
______HP

Note: if only 1 well, $X_B = X_{Bi}$

3. Brake horsepower (BHP):

$$BHP = \frac{HHP}{.85}$$

(Assume pump efficiency is .85 if not stated): ______HP

4. Kilowatts KWH_1:

$KWH = (BHP)(.802)$ ______KWH_1

(See derivation in Appendix D)

5. Required pump capacity =

$$\frac{X_B}{1440}$$ ______ gpm

INJECTION WELL FIELD COST ESTIMATES

1. Well Cost:

   a. Enter the cost of pipe ($/ft): ______$/ft

   b. Obtain total cost of well pipe ($/ft)(L): ______$

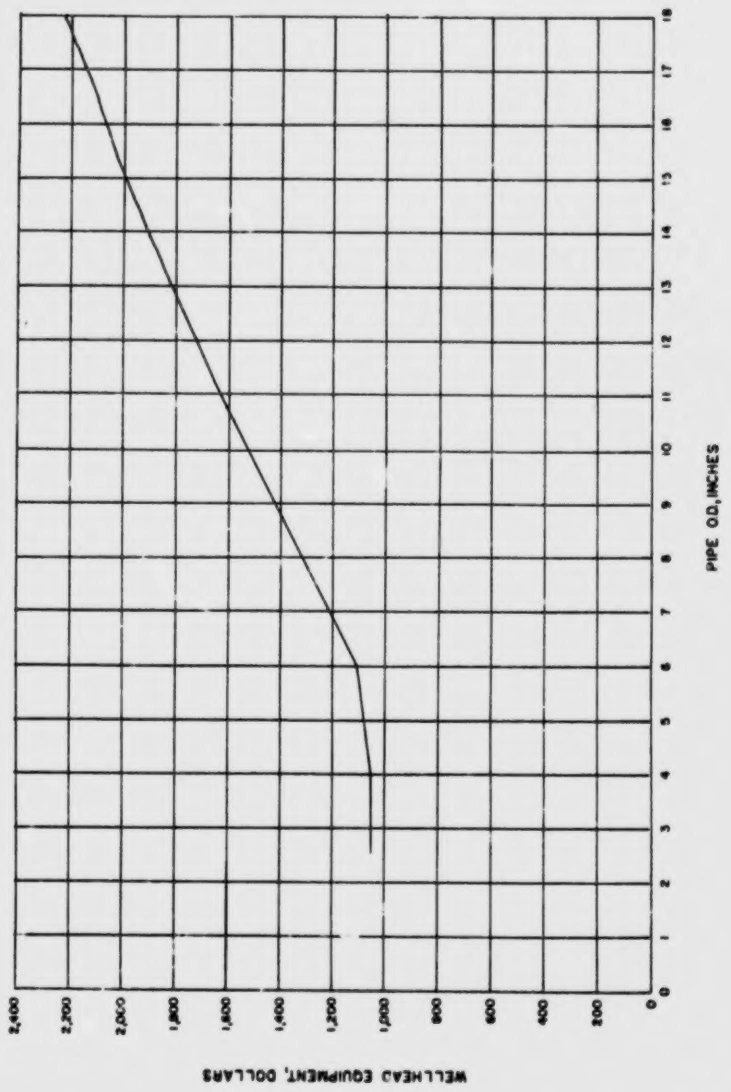
   c. Enter value for cost of well-head equipment vs. O.D. (from Figure 17 or use better cost if available): ______$

   d. Plastic lining:

      (1) Enter value for cost of plastic lining pipe vs. pipe O.D. (from Figure 9 or use better cost if available): ______$/ft

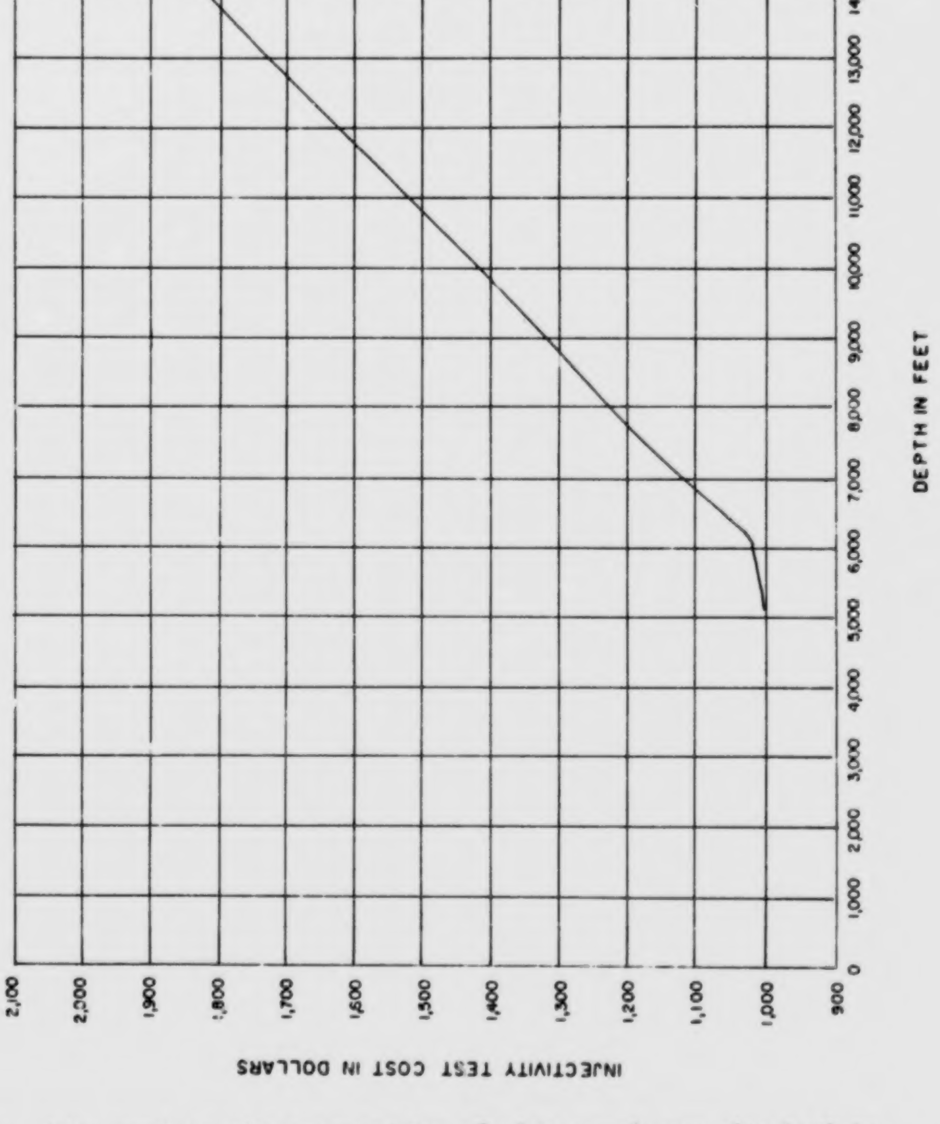
      (2) Cost = ($/ft)(L-h) or ($/ft)(L) if sandstone, i.e., for sandstone lithology = 0 ______$

   e. Enter value for injectivity test cost from Figure 18 : ______$



Note: Data used in the preparation of this graph was obtained in 1962 (Engineering News Record Building Cost Index, ENRBCI, of 570). To update to current year, multiply graph values by (ENRBCI of current year/570).

Figure 17. Cost of Wellhead Equipment in Dollars Versus Tubing Outside Diameter in Inches.[47]



Note: Data used in the preparation of this graph was obtained in 1962 (Engineering News Record Building Cost Index, ENRBCI, of 570). To update to current year, multiply graph values by (ENRBCI of current year/570).

Figure 18. Injectivity Test Cost in Dollars Versus Depth of Well in Feet.[47]

f. Total well cost (T_{wu}):

$T_{wu} = a + b + c + d + e$ ______$/well

g. Total well cost = (T_{wcl}):

T_{wcl} = (No. wells)(cost $/well) ______$

2. Distribution Pipe Cost:

a. For each pipe listed in item 6, "Distribution Piping - Cement-Lined," enter $/ft:

Type	Wt.	lb/ft	Feet	$/ft (lined or unlined)	
______	______	______	______	______	______$
______	______	______	______	______	______$
______	______	______	______	______	______$

Note: May be more or fewer than 3 distribution pipes; one pipe per well.

b. Total feet = ______. Total Distribution Cost (T_{DPC}): ______$

c. Installation and construction cost:

(1) Construction cost (T_{ICC}):

(Assume $.60 per foot or use better value.)

T_{ICC} = ($.60/ft)(total feet) ______$

(2) Right-of-way (ROW):

(Assume $109 per acre with 30' right-of-way or better value).

ROW = ($.075)(total feet) ______$

(3) Total cost of installation and construction (T_{IC}):

$T_{IC} = T_{ICC} + ROW$ ______$

OTHER EQUIPMENT (See Figures 10 and 19)

1. Pump station cost (T_{WPS}): (Enter value from Figure 10 with BHP approximation.) ______$

2. Storage cost (T_{SC}): (With storage volume = 1/3 daily flow = $\frac{X_{Bi}}{3}$, enter from Figure 19.) ______$

3. Treatment plant. This option is explored separately due to its potential application with any of the three types of disposal mechanisms.

INJECTION SYSTEM CAPITAL AND ANNUAL COST

1. Well Field:

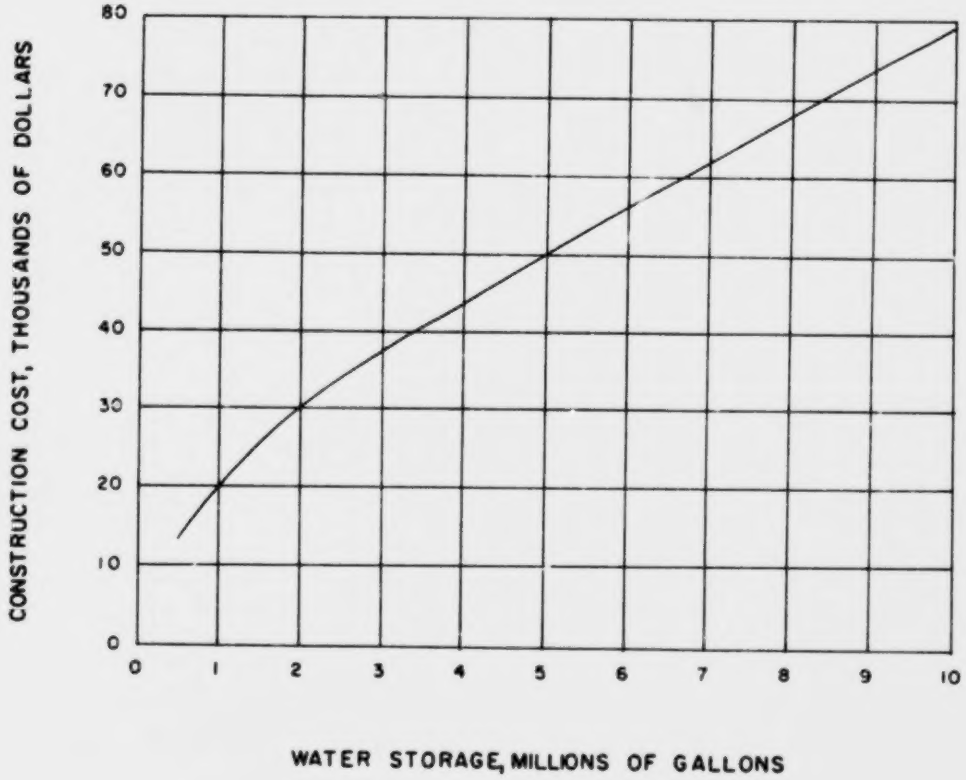
   a. Capital costs:

      (1) Total well cost (T_{WC}):

      $T_{WC} = T_{WC1} + T_{DPC} + T_{IC} + T_{WPS} + T_{SC}$ ______$

      (2) Site cost (S.C.):

      $S.C. = \frac{.25 \text{ acre}}{\text{well}}$ (no. wells)($/acre) ______$



Note: Data used in the preparation of this graph was obtained in 1962 (Engineering News Record Building Cost Index, ENRBCI, of 570). To update to current year, multiply graph values by (ENRBCI of current year/570).

Figure 19. Cost of Water Storage Facilities in Thousands of Dollars Versus Water Storage in Millions of Gallons.[48]

(3) Contingencies = $(.10)(T_{WC}+S.C.)$:

(Assume 10% of well cost and site cost.) ______$

(4) Engineering = $(.10)(T_{WC}+S.C.$ contingencies):

(Assume 10% of well cost, site cost, and contingencies.) ______$

(5) Interest on construction money (i_c):

$i_c = .01625\ ((3) + (4))$ ______$

(Assume 1.625% of cumulative capital costs.) ______$

(6) Total capital cost (T_{CC}):

$T_{CC} = (T_{WC} + S.C. + \text{Conting.} + \text{Engineering} + i_c)$ ______$

b. Annual expenditures:

(1) Operation and maintenance (OM), (enter value from "Estimated Operation and Maintenance" from Figure 11): ______$/year

(2) Supplies and materials = (.0025) (total capital cost):

(Assume .25% of total capital costs.) ______$/year

(3) Annual workovers = (No. wells)($/ft)(ft/well): ______$/year

(4) Payroll overhead = (.15%)(OM):

(Assume 15% of operations and

maintenance.) ______$/year

(5) General and administrative:

(Assume 30% of operation and

maintenance and payroll.) ______$/year

(6) Amortization of capital cost (A):

$$A = (\text{total capital cost}) \left[\frac{i(1+i)^Y}{(1+i)^Y - 1} \right]$$ ______$/year

(7) Subtotal, annual expenditures (ST_{AE}):

$ST_{AE} = ((1) + (2) + (3) + (4) + (5) + (6))$ ______$

(8) Interest on working capital (i_{wc}):

(Assume .7% of other annual costs.)

$i_{wc} = (.007)(\text{Subtotal})$ ______$

(9) Total = $T_{AWC} = (T_{SA} + i_{wc})$ ______$

2. Distribution Pipeline Costs:

a. Capital costs:

(1) Construction costs (T_{IC}):

(See 2.c.(3), under "Injection Well

Field Cost Estimates.") ______$

(2) Contingencies = (.10)(total construction cost)

(Assume 10% of total construction

cost.) ______$

(3) Engineering = 10% (Contingencies + total construction cost)

(Assume 10% of total contingencies and construction cost.) ______\$

(4) Interest on construction money (i_c)

i_c = (.01625)(construction cost, contingencies, and engineering)

(Assume 1.625% of cumulative capital costs.) ______\$

(5) Total distribution pipeline capital cost = T_{IC} + Contingency + Engineering + i_c ______\$

b. Annual expenditures (\$/yr): ______\$

(1) Operation, maintenance, and supplies (OM&S):

OM&S = (.0025)(total dist. pipeline capital cost) ______

(Assume .25% of total distribution capital cost.) ______\$/year

(2) Amortization of capital cost (A):

$$A = (\text{capital cost dis. pipes}) \left[\frac{i(1+i)^Y}{(1+i)^Y - 1} \right]$$

______\$/year

(3) Interest on working capital (i_{wc}):

i_{wc} = (.007)(OM&S + A)

(Assume .7% of other annual costs.) ______\$/year

(4) Total distribution pipeline annual expenditure (T_{DPE}):

$T_{DPE} = OM\&S + A + i_{wc}$ ______$/year

3. Pump Station and Storage:

a. Capital cost:

(1) Pump station cost (Figure 10): ______$

(2) Storage cost (Figure 19): ______$

(3) Total facility cost ((1) + (2)): ______$

(4) Site cost = (no. acres)$\left[\frac{(\$)}{\text{acre}}\right]$: ______$

(5) Contingencies = .10 ((3) + (5))

(Assume 10% of facility and site cost.) ______$

(6) Engineering = .10 ((3) + (5) + (6)):

(Assume 10% of facility and site cost and contingencies.) ______$

(7) Subtotal = ((3) + (5) + (6) + (7)): ______$

(8) Interest on construction money (i_c):

$i_c = (.01625)(\text{Subtotal})$

(Assume 1.625% of cumulative capital cost.) ______$

(9) Total capital cost (CC_i):

$CC_i = T_{ST} + i_{wc}$ ______$

b. Annual Expenditures:

(1) Power cost (P_C):

$P_C = (KWH)(8760)(ECU)$ ______$/year

(See Injection and Power Requirements, KWH)

(2) Enter value from "Operation and Maintenance" from Figure 11 ______$/year

(3) Supplies and materials (C_{SM}):

$C_{SM} = (.0025)(T_{CC})$

(Assume .25% of total capital cost.) ______$/year

(4) Payroll extras = (.15)(OM):

(Assume 15% of Operation and Maintenance cost.) ______$/year

(5) General and administrative (GA):

GA = (.30)(OM + payroll)

(Assume 30% of Operation and Maintenance, and Payroll costs.) ______$/year

(6) Amortization of capital cost (A):

$$A = (\text{capital cost}) \left[\frac{i(1+i)^Y}{(1+i)^Y - 1} \right]$$ ______$/year

(7) Subtotal = (1) + (2) + (3) + (4) + (5) + (6):

______$/year

(8) Interest on working capital (i_{wc}):

$i_{wc} = (.007)(\text{Subtotal})$

(Assume .7% of all annual expenditures.) ______$/year

(9) Total annual expenditure for injection well field (TAE_i):

$TAE_i = (\text{Subtotal} + i_{wc})$ ______$/year

INJECTION COST SUMMARY

1. Total unit cost of injection well field per barrel of brine (TUC_{Bi}):

$$TUC_{Bi} = \frac{TAE_i\ (42)}{(X_B)(365.)}$$

______\$/brl brine

2. Total unit cost of injection well field per barrel of oil (TUC_{Oi}):

$$TUC_{Oi} = \frac{TAE_i\ (42)}{(X_o)(365.)}$$

______\$/brl oil

TOTAL INJECTION SYSTEM COST (Injection Well + Pipeline + Pumping)

1. Total capital cost (TCC_{is}):

$$TCC_{is} = CC_i + CC_p + CC_{ps}$$

______\$

2. Total annual cost (TAE_{is}):

$$TAE_{is} = TAE_i + TAE_p + TAE_{ps}$$

______\$/year

3. Total unit cost for injection system per barrel of brine injected (TUC_{Bis}):

$$TUC_{Bis} = TUC_{Bi} + TUC_{BPPS}$$

______\$/brl brin

4. Total unit cost for injection system per barrel of oil produced (TUC_{Ois}):

$$TUC_{Ois} = TUC_{Oi} + TUC_{OPPS}$$

______\$/brl oil

WATER TREATMENT FOR BRINE DISPOSAL

Generally, there are several degrees and types of brine treatment. The treatment process selected depends on the characteristics of the brine to be treated and the degree of treatment required for disposal or beneficial use of the water. This topic was described more thoroughly in the sections on pollution and water treatment; therefore, it will not be developed here.

This discussion of treatment is oriented to brine handling prior to disposal (although treatment may be necessary prior to other methods of disposal). The treatment process (if it is necessary) can be inserted almost anywhere in the supply and distribution system connecting the production well and disposal device but is usually placed just prior to the disposal system. In this way, the treated water or brine has a minimal chance of being altered prior to injection.

Two general descriptions of the design configuration-cost analysis approach to treatment will be given. The first involves the use of a single, overall relationship developed by Koenig[47] to describe pre-injection treatment. This relationship is displayed graphically as capital and operating costs associated with pre-injection treatment. (This analytical procedure is also followed by the computer program described in Appendix E.)

The second method is to identify undesirable characteristics and present appropriate relationships to handle each case.[52] It should be emphasized that the intent of both of these analyses is not to present or identify exact costs but to sequence the arrangements of either approach to treatment. Also, since this discussion is oriented toward disposal or preparation prior to disposal, a higher order beneficial use could conceivably introduce processes and costs not considered in this analysis.

Table 8 gives treatment operations.

Table 8. TREATMENT OPERATIONS[54]

Operation/Equipment	Objective
1. Baffles.	1. Regulate flow (velocities and directions).
2. Skimming.	2. Remove floating oil.
3. Aeration.	3. Oxidation of soluble ferrous compounds to insoluble ferric compounds and soluble carbonate compounds to insoluble carbonate compounds.
4. Chlorination.	4. Aid in the further oxidation of iron, and control algae and bacterial growths.
5. Chemical coagulation and sedimentation (hydrated lime and alum).	5. Removal of the compounds which would form scales on the reservoir interface; e.g., iron compounds, calcium compounds, and small amounts of hydrocarbon compounds.
6. Filtration (pressure, carbon, and sand).	6. Removal of small particles from sedimentation operation.

Table 9 lists undesirable waste characteristics and removal operations.

Table 9. UNDESIRABLE WASTE CHARACTERISTICS AND REMOVAL OPERATIONS[54]

Undesirable Characteristics	Treatment Operations
1. Suspended Material:	
a. Oils and other floating material.	A.P.I. Separator Skimming Floatation
b. Solids, colloids, etc.	Chemical coagulation Sedimentation Centrifugation Gravity Sand Filtration Pressure Sand Filtration Diatomite Filtration
c. Biological growths (e.g. slime forming algae and bacteria)	Chlorination Filtration
2. Dissolved Substances:	
a. Gases	Aeration Purging Vacuum Degasifer
b. Undesirable ions	pH Adjustment Neutralization Precipitation, Chemical Coagulation Ion Exchange Membrane Process
3. Corrosiveness:	Removal of Gases pH Control

WATER TREATMENT ANALYSIS

The following information is required before beginning the analysis:

1. X_o = Quantity of oil produced with brine in gallons per day. ______gpd

2. X_B = Quantity of brine to be treated in gallons per day. ______gpd

3. MX_B = Quantity of brine to be treated in millions of gallons per day.

   $MX_B = \frac{X_B}{1,000,000}$ ______mgpd

4. i = Discount rate or cost of capital. ______decimal fraction

5. Y = Project life. ______years

DESIGN ANALYSIS

A typical pre-injection system is shown in Figure 20. Components and configuration are reasonable; however, the less the amount of brine to be treated, the smaller the treatment plant. This analysis assumes a minimum of 1,000 gallons of brine to be treated per day, 365 days per year.

1. Capital cost:
   a. Capital cost may be taken directly from Figure 21: ______$
   b. Capital cost may instead be assumed to be composed of principal component costs[52] (enter zero if component not used):
      (1) Primary treatment (sedimentation) cost (C_P):
      $C_P = (.345)(MX_B)^{.708}$ (10547.) ______$

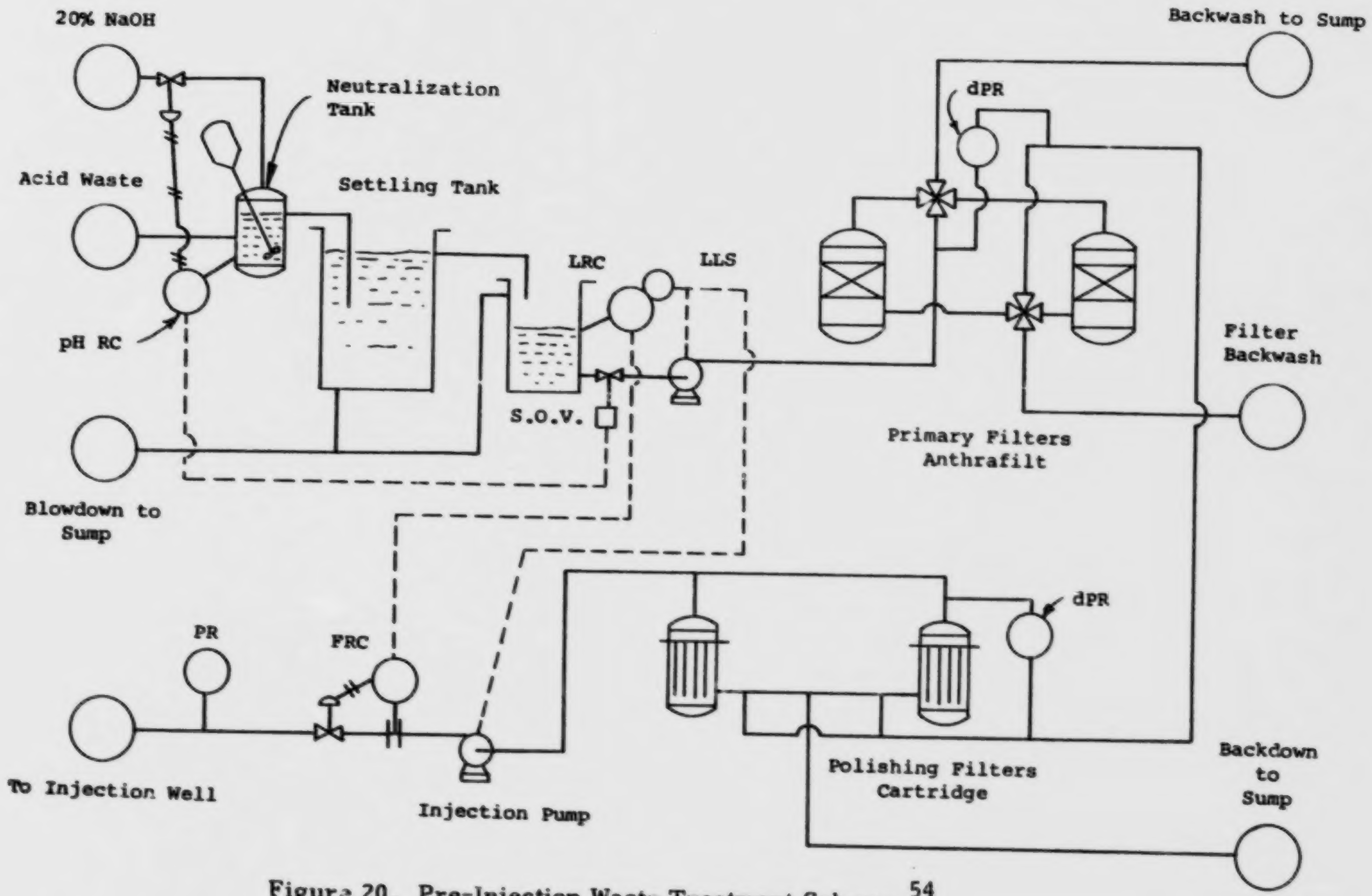
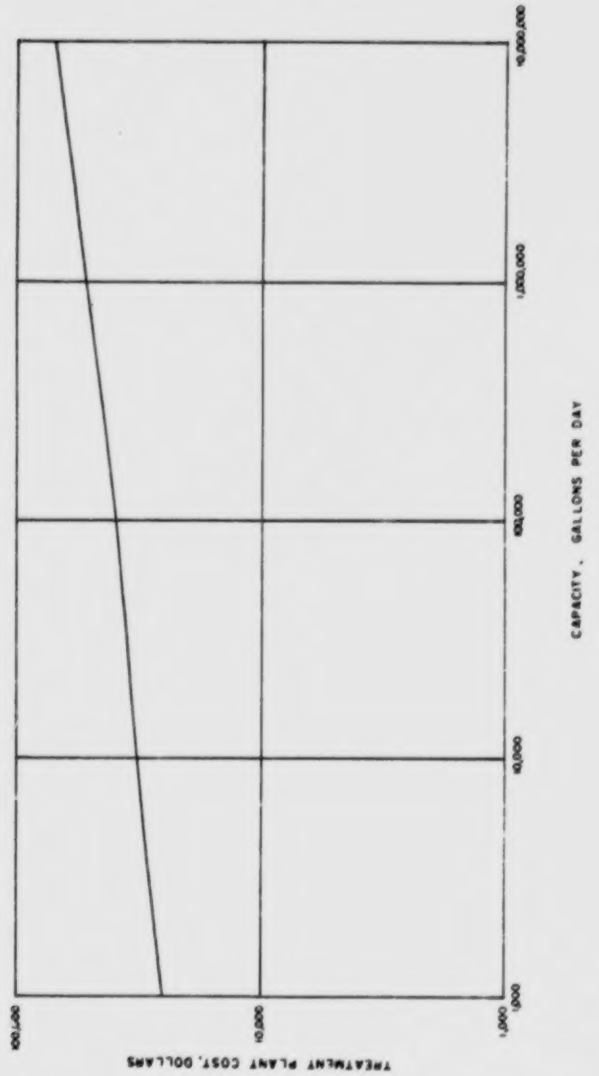

20% NaOH
Acid Waste
pH RC
Blowdown to Sump
Neutralization Tank
Settling Tank
LRC
LLS
S.O.V.
dPR
Backwash to Sump
Filter Backwash
Primary Filters Anthrafilt
PR
FRC
To Injection Well
Injection Pump
Polishing Filters Cartridge
dPR
Backdown to Sump

Figure 20. Pre-Injection Waste Treatment Scheme.[54]



Note: Data used in the preparation of this graph was obtained in 1962 (Engineering News Record Building Cost Index, ENRBCI, of 570). To update to current year, multiply graph values by (ENRBCI of current year/570).

Figure 21. Cost of Treatment Plant in Dollars Versus Plant Capacity in Gallons per Day.[47]

(2) Secondary treatment (aeration)

Cost (C_S):

$C_S = (.531)(MX_B)^{.785}(10547.) - C_P$ ______$

c. Subtotal treatment system construction Cost (enter either a or applicable of (1), (2) (C_{TS}): ______$

d. Contingencies = $(.10)(C_{TS})$:

(Assume 10% of construction cost.) ______$

e. Engineering = (.10)(contingencies + C_{TS})

(Assume 10% of construction cost and contingencies.) ______$

f. Interest on construction money (i_c):

$i_c = (.01625)(C_{TS}$ + contingencies + engineering)

(Assume 1.625% of cumulative capital costs.) ______$

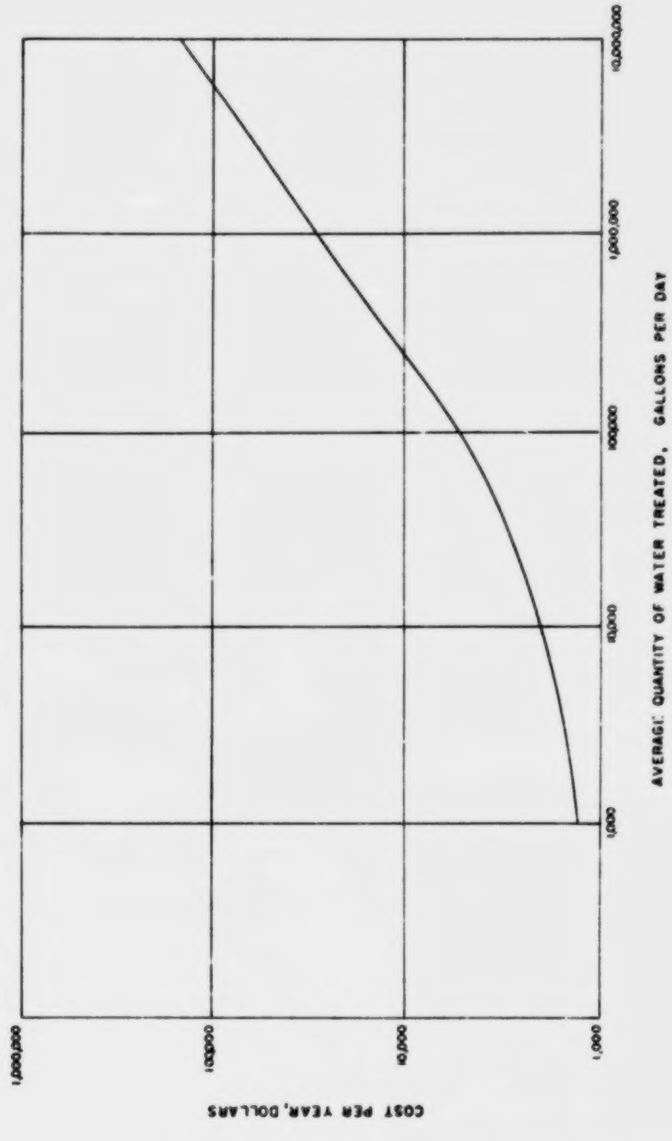
g. Total capital cost (CC_{TS}):

$CC_{TS} = (C_{TS}$ + contingencies + engineering + 1). ______$

2. Annual Cost:

a. Annual expense may be taken directly from Figure 22: ______$/year

b. Annual cost may instead be assumed to be composed of appropriate principal component costs:[52]



Note: Data used in the preparation of this graph was obtained in 1962 (Engineering News Record Building Cost Index, ENRBCI, of 570). To update to current year, multiply graph values by (ENRBCI of current year/570).

Figure 22. Annual Cost of Operation of Injection Water Treatment Plant in Dollars Versus Quantity of Water Treated in Gallons per Day.[47]

(1) Annualized capital cost for appropriate components:

$A_{TS} = CC_{TS} \left[\frac{i(1+i)^Y}{(1+i)^Y-1}\right]$ ______\$/year

(2) Annual Operations and Maintenance for appropriate component (enter zero if component not used).

(a) Primary treatment (sedimentation) cost operation and maintenance (OM_P):

$OM_P = (4.561)(10^{-2})(MX_B)^{-.205}(.565X_B)$

______\$/year

(b) Secondary treatment (aeration) cost operation and maintenance (OM_S)

$OM_S = (8.679)(10^{-2})(MX_B)^{-.2395}(.565X_B) - (OM_P)$

______\$/year

(3) Operation and maintenance cost (OM_{TS}):

$OM_{TS} = OM_P + OM_S$ ______\$/year

(4) Subtotal annual expenditures or sum of component annual costs:

(a) Operation and maintenance (OM_{TS}): ______\$/year

(b) Annual amortized expenditure (A_{TS}):______\$/year

(5) Interest on construction (assume .7%) (i_c):

$i_c = (.007)(OM_{TS} + A_{TS})$ ______\$/year

(6) Total annual expenditure (TAE_{TS}):

$$TAE_{TS} = i_c + OM_{TS} + A_{TS}$$ ______\$/year

(7) Total unit cost of treatment plant per barrel of brine treated (TUC_{BTP}):

$$TUC_{BTP} = \frac{TAE_{TS}\,(42)}{(X_B)(365.)}$$ ______\$/brl brine treatment

(8) Total unit cost of treatment plant per barrel of oil produced (TUC_{OTP}):

$$TUC_{OTP} = \frac{TAE_{TS}\,(42)}{(X_o)(365.)}$$ ______\$/brl oil

SELECTION OF BEST ALTERNATIVE

If more than one disposal method is considered (assuming no treatment), then:

1. Compare TUC_{OIs} with TUC_{OES} with TUC_{OPPS}.
2. Select the least expensive allowable alternative on the basis of lowest annual cost.
3. These TUC values may be compared directly with oil price at the well-head for use in analyzing the impact of disposal on production, as well as total production-disposal expenses.

If treatment is necessary, then:

1. Obtain the value of TUC_{OTP} which is composed of factors most nearly approximating each system's treatment needs.
2. Add appropriate TUC_{OTP} to applicable disposal system.

3. Compare TUC values after treatment costs have been added.
4. Select the allowable disposal alternative based on lowest annual costs.

DEFINITION OF TERMS

H_f = Head loss due to friction (feet)

F' = Length of pipeline (miles)

F = Length of pipeline (feet = $5280F'$)

L = Total depth of well (feet)

X_B = Quantity of disposed brine (gallons per day)

X_o = Quantity of produced oil (gallons per day)

Y = Project life (years)

i = Discount rate; cost of capital (decimal fraction)

EL = Relative elevation of discharge point (feet)

ROW = Right-of-way cost (%/acre)

ECU = Electricity cost ($/KWH)

H_p = Required pumphead (feet)

TAE_p = Total annual pipeline expenditure ($/year)

TAE_{ps} = Total annual pump station expenditure ($/year)

TUC_{opps} = Total unit cost of pipeline and pumping per barrel of oil produced ($/brl oil)

TUC_{BPPS} = Total unit of pipeline and pumping per barrel of brine handled ($/brl brine)

TAE_E = Total annual evaporation pond expenditure (\$/year)

TUC_{OE} = Total unit cost of evaporation pond per barrel of oil produced (\$/brl oil)

TUC_{BE} = Total unit cost of evaporation pond per barrel of brine produced with the oil (\$/brl brine)

TAE_i = Total annual injection well field expenditure (\$/year)

TUC_{Bi} = Total unit cost of injection well field per barrel of brine injected (\$/brl brine)

TCU_{Oi} = Total unit cost of injection well field per barrel of oil produced (\$/brl oil)

TAE_{TS} = Total annual cost of brine treatment plant _______ \$/year

TUC_{BTP} = Total unit cost per barrel of brine treated for treatment plant

$$TUC_{BTP} = \frac{TAE_{TS}}{X_B\ (365)\ (42)}$$ _______ \$/brl brine

TUC_{BTP} = Total unit cost per barrel of oil produced for treatment plant

$$TUC_{OTP} = \frac{TAE_{TS}}{X_O\ (365)\ (42)}$$ _______ \$/brl oil

SECTION VI

IMPROVEMENTS TO INDIVIDUAL DISPOSAL

No discussion of oilfield brine disposal is complete without mentioning two areas which could potentially increase the efficiency of production disposal (as far as lowering brine disposal costs) and result in an additional source of income. The first area is secondary recovery.[55] Actually, secondary recovery is a special kind of beneficial use[56] in which the injected brines are used to displace a portion of the remaining oil in the reservoir. Brines used in secondary recovery may also be used later for some type of industrial or agricultural application such as cooling or irrigation. (See the previous sections on beneficial uses for limitations.) The second type of beneficial use is by-product recovery in which the value attached to the minerals in brine is sufficient to warrant extraction.

SECONDARY RECOVERY

State oil production regulating agencies specify procedures for unitizing a reservoir. Usually, the consent of a majority of the landowners over a reservoir is sufficient to establish a unit (provided the majority is equal to or greater than the percent specified by state law). After or concurrent with the landowners' consent, a formula for dividing oil production revenues is devised and approved by the members of the unit. The next step is to decide how the unit will be run and who will run it. Normal practice is for the largest operator in the field to direct the production and secondary recovery operations of the entire reservoir.

It is not the intent of this publication to discuss waterflooding; however, a summary of the advantages and disadvantages of this method of operation might prove useful to prospective unit participants.[57] Table 10 gives that summary.

Table 10. WATERFLOODING ADVANTACES AND DISADVANTAGES

Advantages	Disadvantages
1. Permits efficient, controlled production of a reservoir for maximum yield at minimum cost.	1. Pool may be too small to justify secondary recovery.
2. Handles large volumes of fluid economically.	2. Pool may have so many landowners that arbitration may be impossible.
3. Eases the burden of disposal.	3. Reservoir characteristics might prevent secondary recovery.
4. Small landowner can participate without drilling.	4. Major operator's interest may be too small to justify his participation.
5. Conserves reservoir energy through higher yields; i.e., more complete production and increased productive life.	5. Pressurization may initiate groundwater pollution (not previously existent in the field) via unplugged abandoned wells or seismographic holes.
	6. Difficulty and expense of locating and plugging vertical holes of communication may preclude developing the field by waterflood.

In addition to references 53 and 58, three publications may be helpful as guidelines in secondary recovery operations: 57, 59, and 60.

MINERAL BY-PRODUCT RECOVERY

There are numerous operations which withdraw saline groundwater and extract salts and minerals.[61, 62, 63, 64, 65] An analysis of a typical mineable midland brine is given in Table 11.

Table 11. MIDLAND BRINE CONSTITUENTS[63]

Constituents	Concentration
Calcium Chloride ($CaCl_2$)	190,000 ppm
Magnesium Chloride ($MgCl_2$)	36,500 ppm
Sodium Chloride (NaCl)	52,000 ppm
Potassium Chloride (KCl)	16,800 ppm
Bromine (Br_2)	2,600 ppm
Iodine (I_2)	38 ppm

Relatively recently, there have been several publications advocating the potential of mineral by-product recovery from oilfield brines. A valid basis for this interest is the estimate that approximately 8×10^9 barrels of brine are produced each year with the oil produced in the United States.[66] These brines contain more than 1.3×10^8 tons of minerals and salts (32 pounds per barrel) (see Table 1).

Another article developed the point that based on sheer quantity, the mineral content of oilfield brine disposed of each year is worth more than $3 billion.[1] As a rough estimate, Tables 12 and 13[67] indicate the dependence of the market value of specific recoverable chemicals on the quantity of fluid handled and depth of reservoir.

When Table 12 is used with Table 13, it becomes apparent that considerable profits can result if it is possible to process a concentrated brine either at the surface of the ground after oil separation or upon raising the brine from a fairly shallow depth.

Table 12. DOLLAR VALUE OF DISSOLVED CHEMICALS A BRINE SHOULD CONTAIN PER 1 MILLION POUNDS (2,840 bbl) OF BRINE PRODUCED FROM A GIVEN DEPTH

Value ($/million lb of brine)	Depth of Well (ft)
210	2,500
440	7,000
650	10,000

Table 13. AMOUNT OF ELEMENT PER 1 MILLION POUNDS OF BRINE NECESSARY TO PRODUCE CORRESPONDING CHEMICAL PRODUCT WORTH $250

Element	Concentration (ppm)	Product
Sodium	50,000	Sodium chloride
Potassium	14,000	Potassium chloride
Lithium	170	Lithium chloride
Magnesium	8,000	Magnesium chloride
Calcium	11,000	Calcium chloride
Strontium	4,000	Strontium chloride
Boron	1,400	Sodium borate
Bromine	1,700	Bromine
Iodine	250	Iodine
Sulfur	5,300	Sodium sulfate

These two tables should be used together; i.e., 1 million pounds (2,840 barrels) of brine containing 50,000 ppm sodium and 1,700 ppm bromine produced from a depth of 7,000 feet would be worth $250 + $250 - $440 = $60 (assuming Table 12 gives cost of mining).

The Dow Chemical Company has mined iodine (10 to 135 ppm) from California oil brines;[65] however, little has appeared recently to indicate the extent of mineral mining or by-product recovery. Perhaps one reason for the seeming general lack of activity can be explained by operating figures for some of the companies currently mining bromine in the Smackover region of Arkansas (not intentionally producing oil). These figures are given in Table 14.

Table 14. BRINE QUANTITIES

Company	Volume (bbl/month)	Concentration Bromine (ppm)	Depth (ft)
1	2,055,818	4,800	8,300
2	175,797	4,000	7,600
3	355,895	5,000	7,600
4	4,823,242	4,500	8,400
5	2,038,923	4,500	7,700
6	2,691,120	4,500	7,400

Company No. 6 processes approximately 3.16 million pounds of brine a day. Assuming it is worth (2.65)($250) = $663 per million pounds of brine, then the company could have a gross revenue from this activity of $2,090 - (3.16)(450) = $668 per day.

Unfortunately, the brine flow from most oil wells or collection of oil wells is considerably less than this rate. The reluctance of most small operators to get into mineral by-product operations seems mainly due to the following reasons:

1. There are relatively high capital and operating costs, especially in remote areas.
2. Proration and well spacing requirements make accumulation of high brine volumes expensive.
3. Occasional oil in the brine fouls separating mechanisms, especially if the process of chelation is used.[40]
4. Equipment is fairly complicated to operate.
5. Market for minerals is variable.

While it appears that several of the majors are conducting exploratory efforts in this area, mineral by-product recovery has few possibilities for the individual small independent. On the basis of a sizeable unit or similar cooperative group, however, the individual small operator acquires the resource potential of a large operator (from the reservoir operations point of view), and such operations as mineral by-product recovery enter his realm as a potential source of additional profit.

SECTION VII

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APPENDICES

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APPENDIX A

SUMMARY OF STATE OIL REGULATING AGENCIES

ALABAMA

1. Regulating Agency:

State Oil & Gas Board of Alabama
P.O. Drawer O
Walter Bryan Jones Hall
University, Alabama 35486

2. Publication of Regulations:

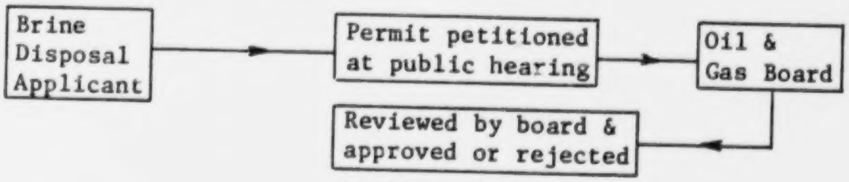
Oil & Gas Laws of Alabama with Oil & Gas Board Forms and Definitions of Oil and Gas Terms

Geological Survey of Alabama
Reprint Series 20
(1967)

3. Coordinating Agency:

Alabama Water Improvement Commission
Montgomery, Alabama

4. Application Flow Chart:


Brine Disposal Applicant
Permit petitioned at public hearing
Oil & Gas Board
Reviewed by board & approved or rejected

5. Allowable Methods of Disposal:

Injection.

Pits, lined.

Pits, unlined (depending on soil).

6. Permit Costs

None.

ALASKA

1. Regulating Agency:

Department of Natural Resources
Oil and Gas Conservation Committee
3001 Porcupine Drive
Anchorage, Alaska 99504

2. Publication of Regulations:

Oil and Gas Conservation Regulations and Statutes
(1969)

3. Coordinating Agencies:

Department of Health and Welfare
Pouch H
Juneau, Alaska 99801

Environmental Protection Agency
Alaska Operations Office
Room 8, Federal Building
605 Fourth Avenue
Anchorage, Alaska 99501

No brine disposal permits to date.

No regulations on brine disposal.

ARIZONA

1. Regulating Agency:

Oil & Gas Conservation Commission
State of Arizona
4515 North 7th Avenue
Phoenix, Arizona 85013

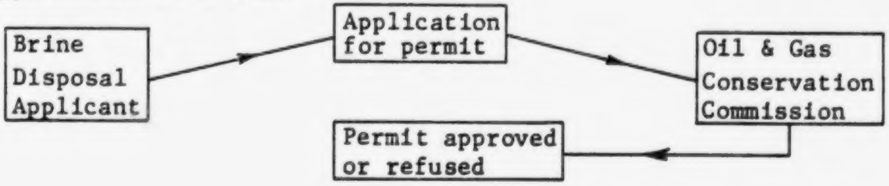
2. Publication of Regulations:

Rules and Regulations,
The Oil and Gas Conservation Commission
of the State of Arizona
(1965)

3. Coordinating Agency:

Department of Health
Fifth Floor
Goodrich Building
14 North Central Avenue
Phoenix, Arizona 85004

4. Application Flow Chart:


Brine Disposal Applicant
Application for permit
Oil & Gas Conservation Commission
Permit approved or refused

5. Allowable Methods of Disposal:

Injection.

Pits, lined.

Pits, unlined (where approved depending on soil).

ARIZONA (Cont)

6. Permit Costs:

Injection: $25.00 (plus $5,000 plugging bond).

Pits: No permit required.

ARKANSAS

1. Regulating Agency:

State of Arkansas Oil & Gas Commission
Oil & Gas Building
El Dorado, Arkansas

2. Publication of Regulations:

General Rules & Regulations Relating
to Oil & Gas
Order No. 2-39
(revised February 1956)

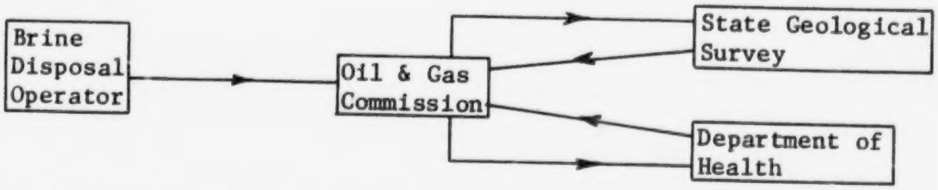
3. Coordinating Agencies:

State Geological Survey
State Capitol Building
(Director, Norman F. Williams)

State Department of Health
4815 W. Markham Street
Little Rock, Arkansas 72201

4. Application Flow Chart:

ARKANSAS (Cont)


Brine Disposal Operator
Oil & Gas Commission
State Geological Survey
Department of Health

Note: The commission, in passing on applications for the use of non-producing formations for disposal formations, will be advised by the technical recommendations of the State Geological Survey and the State Board of Health in determining whether such formations may be safely and legally used.

5. Allowed Disposal Methods:

   Injection.

   Ponds, lined.

   Ponds, unlined.

6. Disposal Permit Costs:

   Injection: None.

   Ponds: None.

CALIFORNIA

1. Regulating Agency:

   Department of Conservation
   Division of Oil & Gas
   1416 Ninth Street
   Sacramento, California 95814

2. Publication of Regulations:

   California Laws for Conservation of Petroleum and Gas
   (1968)

3. Coordinating Agency:

   California State Water Resources
   Control Board
   Room 1140, 1416 Ninth Street
   Sacramento, California 95814

4. Allowable Methods of Disposal:

   Injection.

   Pits, lined.

   Pits, unlined (depending on soil).

   Discharge into ocean.

5. Permit Costs:

   None listed in regulations.

COLORADO

1. Regulating Agency:

   Oil & Gas Conservation Commission
   Room 237, Columbine Building
   1845 Sherman Street
   Denver, Colorado 80203

COLORADO (Cont)

2. Publications of Regulations:

Rules & Regulations, Rules of
Practice and Procedure and
Oil and Gas Conservation Act
(1970)

3. Coordinating Agencies:

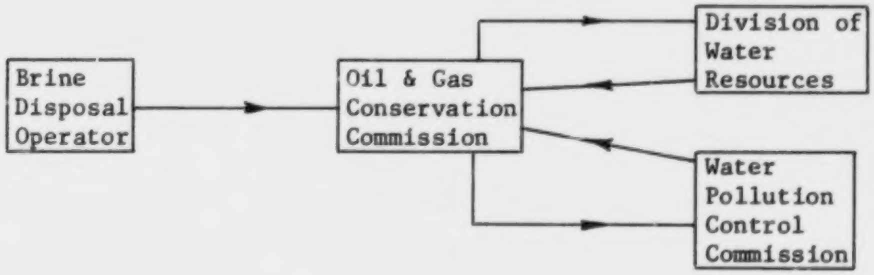
Division of Game,
Fish & Parks
6060 Broadway
Denver, Colorado 80221

Water Pollution Control Commission
4210 E. 11th Avenue
Denver, Colorado 80220

Division of Water Resources
1845 Sherman Street
Denver, Colorado 80203

Geological Survey
1845 Sherman Street
Denver, Colorado 80203

4. Application Flow Chart:


Brine Disposal Operator
Oil & Gas Conservation Commission
Division of Water Resources
Water Pollution Control Commission

COLORADO (Cont)

Note: Copies of the application are given to the Division of Water Resources and the Water Pollution Control Commission for comments. If they have no objection and there is no objection from land owners near the well site, then the application is approved.
No permit needed for pits.

5. Allow Disposal Methods:

Injection.

Pits, lined.

Pits, unlined (depending on soil).

6. Permit Costs:

Injection: $75 (plus $5,000 plugging bond per well or $15,000 blanket bond).

Pits: None.

CONNECTICUT

No regulating agency (no production).

DELAWARE

No regulating agency (no production).

FLORIDA

1. Regulating Agency:

Department of Natural Resources
Bureau of Geology
Oil & Gas Administration
P.O. Drawer 631
Tallahassee, Florida 32302

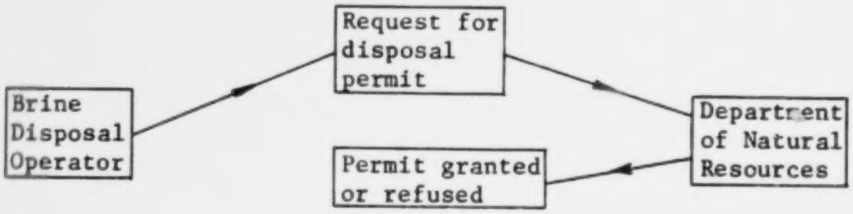
2. Publication of Regulations:

General Rules and Regulations Governing the Conservation of Oil and Gas in Florida
(1962)

3. Coordinating Agency:

Department of Air and Water
Pollution Control
P.O. Drawer 631
Tallahassee, Florida 32302

4. Application Flow Chart:


Request for disposal permit
Brine Disposal Operator
Department of Natural Resources
Permit granted or refused

Note: All applications for permits for disposal of brine are made through the Oil and Gas Administrator and acted on by the Executive Board of the Department of Natural Resources, which is the Cabinet and the Governor. After a public hearing, rules for use of the injection well are devised and an order from the department is issued.

5. Allowable Methods of Disposal:

   Injection only.

6. Permit Costs:

   None.

IDAHO

No regulating agency (no production).

ILLINOIS

1. Regulating Agency:

   Department of Mines & Minerals
   Division of Oil & Gas
   400 South Spring Street, Room 112
   Springfield, Illinois

2. Publication of Regulations:

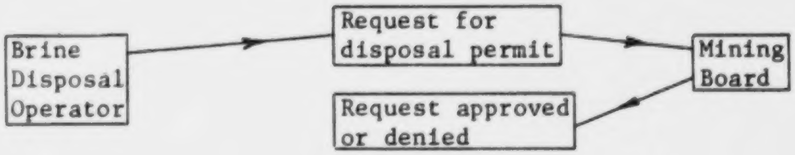
   An Act in Relation to Oil, Gas Coal & Other Surface & Underground Resources and Rules and Regulations
   (1969)

3. Coordination Agency:

ILLINOIS (Cont)

Department of Mines & Minerals
Mining Board
400 South Spring Street, Room 112
Springfield, Illinois

4. Application Flow Chart:


Brine Disposal Operator
Request for disposal permit
Mining Board
Request approved or denied

Note: Application either accepted or refused by Mining Board within 10 days after receipt. Application must be resubmitted each year. Sites subject to inspection by Mining Board.

5. Allowed Disposal Methods:

Injection, drilled or converted well.

Ponds, lined or unlined (depending on soil characteristics).

6. Disposal Permit Costs:

Injection: $40/year (plus $1,000 plugging bond per well or $2,500 blanket bond).

Ponds: None, but permit must be resubmitted each year.

INDIANA

1. Regulating Agency:

INDIANA (Cont)

Department of Natural Resources
Division of Oil & Gas
606 State Office Building
Indianapolis, Indiana 46204

2. Publication of Regulations:

Indiana Division of Oil & Gas
Department of Natural Resources
Rules and Regulations
(1964)

3. Coordination Agencies:

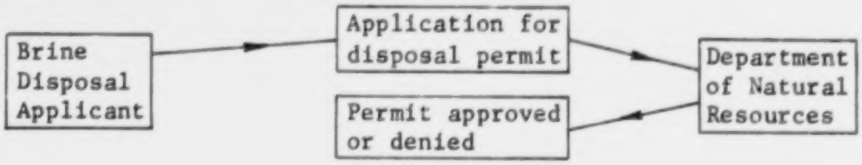
Indiana State Board of Health
Stream Pollution Control Board
1330 W. Michigan Street
Indianapolis, Indiana

Indiana State Board of Health
Water Pollution Control
1330 W. Michigan Street
Indianapolis, Indiana

Indiana State Board of Health
Industrial Waste Disposal Section
1330 W. Michingan Street
Indianapolis, Indiana

Indiana Geological Survey
611 North Walnut Grove Avenue
Bloomington, Indiana 47401

4. Application Flow Chart:


Brine Disposal Applicant
Application for disposal permit
Department of Natural Resources
Permit approved or denied

INDIANA (Cont)

Note: All applications for brine disposal permits are submitted to the Department of Natural Resources for processing. If there is any particular question in regard to a disposal application, one or more agencies may be contacted. If there are no questions the permit is processed and issued under the Statutes and Regulations. Any applications for salt water evaporation pits are also submitted to this office and each pit is then checked in the field for size, type of construction, etc. If the pit meets all requirements, a permit is issued for one year only. The operator must re-apply for a permit each year, and the pit is checked on each application.

5. Allowable Methods of Disposal:

Injection.

Pits, lined.

Pits, unlined (depending on soil).

6. Permit Costs:

Injection: $25 for new well, none for converted well.

Pits: None.

IOWA

No production.

1. Regulating Agency:

Iowa Natural Resources Council
Grimes State Office Building
Des Moines, Iowa 50319

2. Publication of Regulations:

   Iowa Natural Resources Council
   Code Chapter 84
   Relating to Oil & Gas Wells
   (1966)

KANSAS

1. Regulating Agency:

   State Corporation Commission
   State Office Building
   Topeka, Kansas 66612

2. Publication of Regulations:

   General Rules and Regulations for the Conservation of Crude Oils and Natural Gas
   (1966)

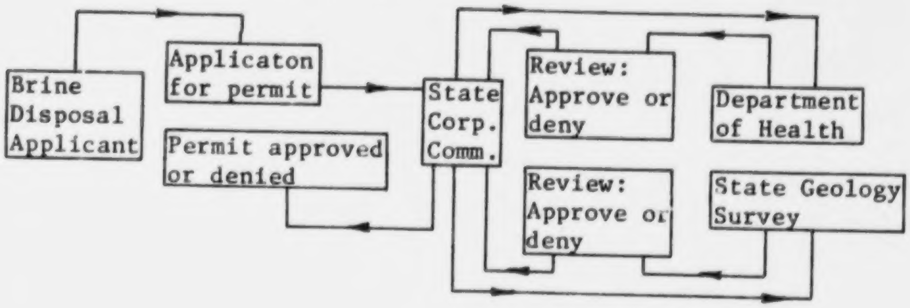
3. Coordination Agencies:

   Kansas State Department of Health
   State Office Building
   Topeka, Kansas 66612

   State Geological Survey
   University of Kansas
   Lawrence, Kansas 66044

4. Application Flow Chart:

KANSAS (Cont)


Brine Disposal Applicant
Applicaton for permit
Permit approved or denied
State Corp. Comm.
Review: Approve or deny
Review: Approve or deny
Department of Health
State Geology Survey

5. Allowable Methods of Disposal:

   Injection.

   Pits, lined.

   Pits, unlined (depending on soil).

6. Permit Costs:

   Injection: $15.00 where one lease is involved, $5.00 for each additional lease.

   Pits: None.

KENTUCKY

1. Regulating Agency:

   Department of Mines and Minerals
   P.O. Box 680
   120 Graham Avenue
   Lexington, Kentucky 40501

2. Publication of Regulations:

   Rules and Regulations Affecting the Oil and Gas Industry in Kentucky
   (1967)

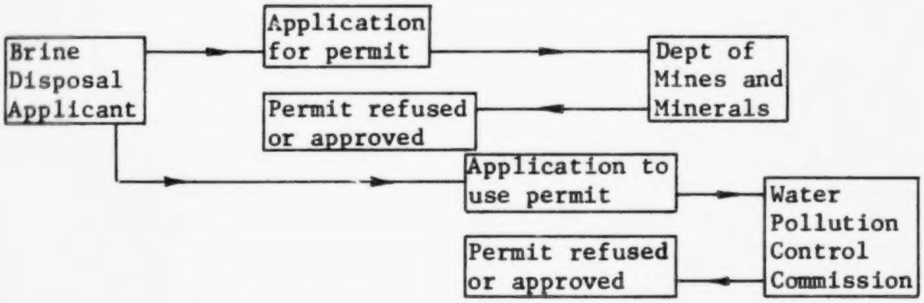
KENTUCKY (Cont)

3. Coordinating Agencies:

Water Pollution Control Commission
275 East Main Street
Frankfort, Kentucky 40601

Department of Fish and Wildlife
State Office Building Annex
Frankfort, Kentucky 40601

4. Application Flow Chart:


Brine Disposal Applicant
Application for permit
Dept of Mines and Minerals
Permit refused or approved
Application to use permit
Water Pollution Control Commission
Permit refused or approved

Note: Drilling is controlled by Department of Mines and Minerals, and use of wells is controlled by Water Pollution Control Commission.

5. Allowable Methods of Disposal:

Injection.

Pits, lined.

Pits, unlined (depending on soil).

6. Permit Costs:

Injection: \$10(plus \$10,000 plugging bond).

Pits: None.

LOUISIANA

1. Regulating Agency:

Department of Conservation
Louisiana Geological Survey
Geology Building
Box G
University Station
Baton Rouge, Louisiana 70903

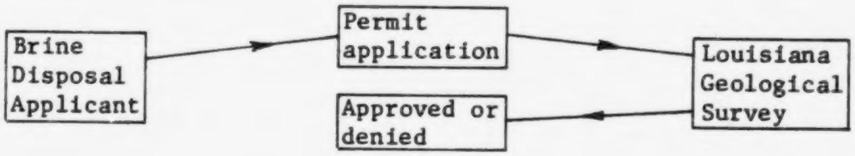
2. Publication of Regulations:

Salt Water & Waste Disposal Wells
State Regulations & Geological Problems
(Revised, 1968)

3. Coordination Agency:

None.

4. Application Flow Chart:


Brine Disposal Applicant
Permit application
Louisiana Geological Survey
Approved or denied

5. Allowable Methods of Disposal:

Injection.

Pits, lined.

Pits, unlined.

In tide-affected waters (waters unfit for human comsumption or agricultural purposes).

6. Permit Costs:

No costs given.

MAINE

No production.

1. Regulating Agency:

Maine Mining Bureau
State House
Augusta, Maine 04330

2. Publication of Regulations:

Maine Mining Law for State-Owned Lands
(1969)

MARYLAND

Natural Gas Production.

1. Regulating Agency:

Maryland Geological Survey
214 Latrobe Hall
John Hopkins University
Baltimore, Maryland 21218

2. Publication of Regulations:

Rules & Regulations Governing
Oil & Gas Wells
(1964)

3. Coordinating Agency:

Department of Water Resources
State Office Building
Annapolis, Maryland 21401

Note: Above agency is responsible for regulating the quality of surface and ground water in Maryland.

4. Allowable Method of Disposal:

No rules or regulations for brine disposal in publication of regulations.

MASSACHUSETTS

No regulating agency (no production).

MICHIGAN

1. Regulating Agency:

Oil and Gas Section (Regulatory Control Unit)
Michigan Geological Survey Division
Department of Natural Resources
Stevens T. Mason Building
Lansing, Michigan 48900

MICHIGAN (Cont)

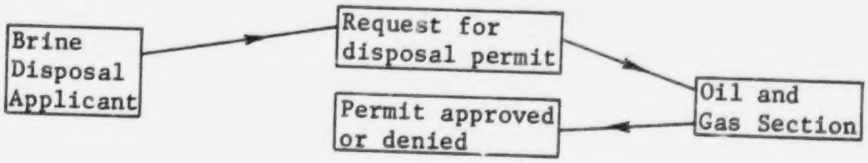
2. Publication of Regulations:

   General Regulations Governing Oil & Gas Operations in the State of Michigan (1963)

3. Coordination Agency:

   None.

4. Application Flow Chart:


Brine Disposal Applicant
Request for disposal permit
Oil and Gas Section
Permit approved or denied

5. Allowable Methods of Disposal:

   Injection only.

6. Permit Costs:

   Injection: $25.00 (plus $6,000 plugging bond per well or $15,000 blanket bond).

MINNESOTA

No regulating agency (no production).

MISSISSIPPI

1. Regulating Agency:

State Oil & Gas Board
1207 Woolfork State Office Building
P.O. Box 1332
Jackson, Mississippi

2. Publication of Regulations:

State Oil & Gas Board
State of Mississippi
Statutes Rules of
Procedure Statewide
Rules and Regulations
(1970)

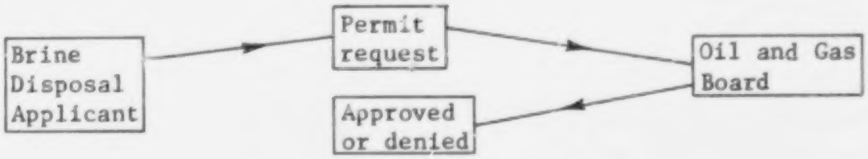
3. Coordination Agencies:

Mississippi Air & Water Pollution
  Control Commission
Robert E. Lee Office Building
Jackson, Mississippi 39201

Mississippi Board of Water Commissioners
416 N. State Street
Jackson, Mississippi 39201

Note: Agencies consulted in cases involving pollution or probable pollution.

4. Application Flow Chart:


Brine Disposal Applicant
Permit request
Oil and Gas Board
Approved or denied

MISSISSIPPI (Cont)

5. Allowable Methods of Disposal:

Injection.

Pit, unlined (in impervious soil).

Pit, lined (in porous soil).

Into receiving bodies of water when not prohibited by State Fish and Game Commission or other regulatory bodies.

6. Permit Costs:

Injection: $50 for new wells, $25 for converted wells.

Earthen pits: None.

Discharge into receiving body of water: None.

MISSOURI

1. Regulating Agency:

Missouri State Oil and Gas Council
P.O. Box 250
Rolla, Missouri

2. Publication of Regulations:

State of Missouri Rules and Regulations Governing Practice and Procedure Before the State Oil & Gas Council Under the Provisions of Senate Bill No. 13
Second Extra Session, 73rd General Assembly
(1970)

MISSOURI (Cont)

3. Coordinating Agency:

Missouri State Oil and Gas Council
P.O. Box 250
Rolla, Missouri

Note: The State Oil & Gas Council is composed of one staff member from each of the following State agencies with the State Geologist as active administrator.

1. Division of Geological Survey and Water Resources.
2. Division of Commerce and Indsutrial Development.
3. Missouri Public Service Commission.
4. Water Pollution Board.
5. University of Missouri (a professor of petroleum engineering).

4. Allowable Methods of Disposal:

Injection.

Note: Pertinent data concerning details of the proposed operation shall be submitted by letter to the State Geologist for approval.

5. Permit Costs:

Injection: $25.00

MONTANA

1. Regulating Agency:

Oil & Gas Conservation Commission
325 Fuller Avenue
Box 217
Helena, Montana 59601

MONTANA (Cont)

2. Publication of Regulations:

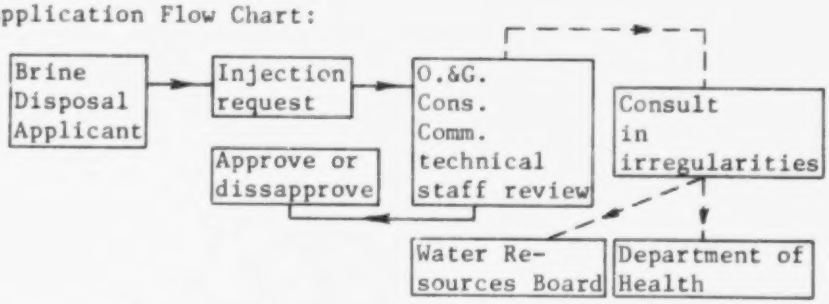
General Rules & Regulations and
Rules of Practice & Procedure
Relating to Oil & Gas
(1954)

3. Coordinating Agencies:

State Department of Health
Cogswell Building
Helena, Montana 59601

Water Resources Board
Mitchell Building
Helena, Montana 59601

4. Application Flow Chart:


Brine Disposal Applicant
Injection request
O.&G. Cons. Comm. technical staff review
Consult in irregularities
Approve or dissapprove
Water Resources Board
Department of Health

Note: The State Department of Health and the Water Resources Board report and consult on water pollution.

5. Allowed Disposal Methods:

Injection. (encouraged)

Pits, lined.

Pits, unlined.

MONTANA (Cont)

6. Permit Costs:

Injection:	Depth	Cost
	0' - 3,500'	$ 25.00
	3,501' - 7,000'	$ 75.00
	7,000' - below	$150.00

(plus $5,000 to $20,000 bond. See page 12 of Regulations.)

Pits. No permits required.

NEW HAMPSHIRE

No regulating agency (no production).

NEW JERSEY

No regulating agency (no production).

NEW MEXICO

1. Regulating Agency:

New Mexico Oil Conservation Commission
P.O. Box 2088
Santa Fe, New Mexico 87501

2. Published Regulations:

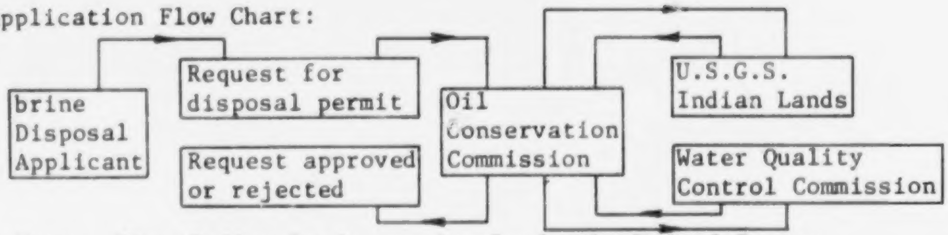
State of New Mexico Oil Conservation Commission
Rules & Regulations
(1968)

NEW MEXICO (Cont)

3. Coordinating Agency:

New Mexico Water Quality Control Commission
P.O. Box 2088
Santa Fe, New Mexico 87501

4. Application Flow Chart:


brine Disposal Applicant
Request for disposal permit
Request approved or rejected
Oil Conservation Commission
U.S.G.S. Indian Lands
Water Quality Control Commission

Note: When Indian lands are involved, the United States Geological Survey is consulted. Normally, the Water Quality Control Commission acts as consultant to the Oil Conservation Commission. The Water Quality Control Commission is made up of the heads of the Oil Conservation Commission, Department of Health and Social Services, Department of Game and Fish, Department of Agriculture, and one citizen at large.

5. Allowable Methods of Disposal:

Injection.

Pits, lined.

Pits, unlined (depending on soil).

6. Permit Costs:

Injection: None (but $10,000 plugging bond and $10,000 performance bond on treatment plants).

Pits: None.

NEW YORK

1. Regulating Agency:

   Division of Mineral Resources
   Department of Environmental Conservation
   Albany, New York 12201

2. Publication of Regulations:

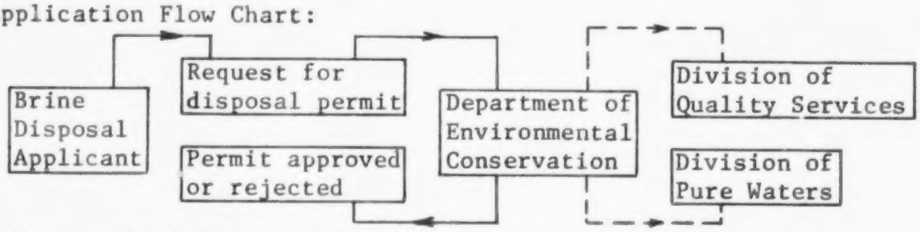
   State of New York, Division of Mineral Resources
   Environmental Conservation Department
   Bureau of Oil and Gas Rules and Regulations
   (1966)

3. Coordinating Agencies:

   Division of Quality Services
   Department of Environmental Conservation
   Albany, New York 12201

   Division of Pure Waters
   Department of Environmental Conservation
   Albany, New York 12201

4. Application Flow Chart:


Brine Disposal Applicant
Request for disposal permit
Permit approved or rejected
Department of Environmental Conservation
Division of Quality Services
Division of Pure Waters

   Note: The Divisions of Quality Services and Pure Waters consult only in cases where irregularities exist.

5. Allowable Methods of Disposal:

   Injection.

NEW YORK (Cont)

Pits, lined.

Pits, unlined (depending on soil).

6. Permit Costs:

Injection: None (but $2,000 plugging bond for new wells and $1,000 plugging bond for old wells).

NEVADA

1. Regulating Agency:

Nevada Oil & Gas Conservation Commission
c/o Nevada Bureau of Mines
University of Nevada
Reno, Nevada 89507

2. Publication of Regulations:

Oil & Gas Conservation Law and General Rules & Regulations (1954)

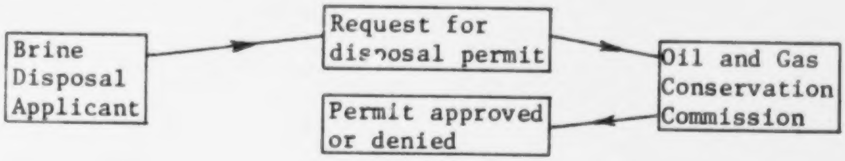
3. Coordinating Agency:

None.

Note: Only 13 wells and three operators in state.

NEVADA (Cont)

4. Application Flow Chart:


Brine Disposal Applicant
Request for disposal permit
Oil and Gas Conservation Commission
Permit approved or denied

5. Allowable Methods of Disposal:

Injection.

Pits, lined.

Pits, unlined (depending on soil).

6. Permit Costs:

Injection: None (but $2,500 plugging bond).

Pits: None.

NEBRASKA

1. Regulating Agency:

Nebraska Oil & Gas Conservation Commission
Box 399
Sidney, Nebraska

2. Publication of Regulations:

Rules & Regulations of the Nebraska Oil & Gas Conservation Commission (1969)

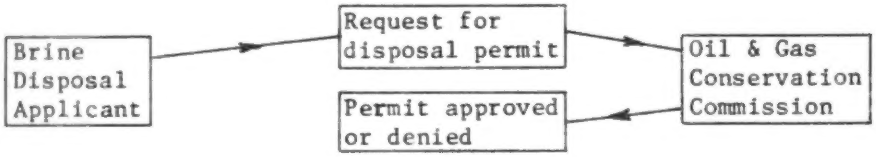
NEBRASKA (Cont)

3. Coordination Agencies:

Department of Health
State Capitol Building
Lincoln, Nebraska

Nebraska Geological Survey
Nebraska Hall
Lincoln, Nebraska

4. Application Flow Chart:


Brine Disposal Applicant
Request for disposal permit
Oil & Gas Conservation Commission
Permit approved or denied

5. Allowable Disposal Methods:

Injection only.

6. Permit Costs:

Injection. None (but $2,500 plugging bond).

NORTH CAROLINA

No regulating agency (no production).

NORTH DAKOTA

1. Regulating Agency:

North Dakota Industrial Commission
University Station
Grand Forks, North Dakota 58201

2. Publication of Regulations:

General Rules and Regulations for the Conservation of Crude Oil and Natural Gas (1969)

3. Coordinating Agency:

None.

4. Allowable Methods of Disposal:

Injection.

Pits, lined (in permeable soil).

Pits, unlined (in impermeable soil).

5. Permit Costs:

Permits must be obtained for both pits and injection wells, but no prices given.

OHIO

1. Regulating Agency:

Department of Natural Resources

Division of Oil & Gas
1500 Dublin Road
Columbus, Ohio 43215

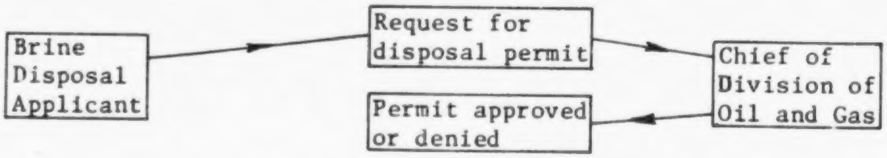
2. Publication of Regulations:

   Ohio Oil & Gas Law
   Revised Code Chapter 1509
   with Rules & Regulations
   (1970)

3. Coordinating Agency:

   None.

4. Application Flow Chart:


Brine Disposal Applicant
Request for disposal permit
Chief of Division of Oil and Gas
Permit approved or denied

Note: The Chief of the Division of Oil and Gas either accepts or rejects the application for disposal permit.

5. Allowable Disposal Methods:

   Injection.

   Pits, lined.

   Pits, unlined (depending on soil).

6. Permit Costs:

   Injection: None.

   Pits: None.

OKLAHOMA

1. Regulating Agency:

   Oil Corporation Commission
   Jim Thorpe Building
   Oklahoma City, Oklahoma 73105

2. Publication of Regulations:

   Regulations of the Oklahoma Corporation Commission
   Conservation Division
   (1969)

3. Coordination Agency:

   Department of Pollution Control
   Jim Thorpe Building
   Oklahoma City, Oklahoma 73105

   Note: Copies of all applications for subsurface disposal are sent to the other member agencies of the Department of Pollution Control for their review and comments.

4. Allowable Methods of Disposal:

   Injection only.

5. Permit Costs:

None.

OREGON

No production in 1971.

1. Regulating Agency:

Department of Geology & Mineral Resources
1069 State Office Building
Portland, Oregon 97201

2. Publication of Regulations:

Rules & Regulations for the Conservation of Oil & Natural Gas and Laws relating to Development of Oil & Gas Minerals
(1962)

3. Coordinating Agency:

Department of Environmental Quality
720 State Office Building
Portland, Oregon 97201

4. Allowed Disposal Methods:

Injection.

Pits, lined.

Pits, unlined (depending on soil).

5. Cost of Permits:

No production. No permits issued as of February 1971.

PENNSYLVANIA

1. Regulating Agency:

Department of Mines & Minerals Industries
Oil & Gas Division
Towne House Apartments
660 Boas Street
Harrisburg, Pennsylvania

2. Publication of Regulations:

Commonwealth of Pennsylvania
Compilation of Oil and Gas Laws
Administered by the Department of Mines
and Mineral Industries, Oil and Gas Division
(1969)

3. Coordination Agency:

Sanitary Water Board
Department of Health
Towne House Apartments
660 Boas Street
Harrisburg, Pennsylvania

Note: The Oil and Gas Division coordinated with the Sanitary Water Board in the adoption of rules for the prevention of stream pollution.

PENNSYLVANIA (Cont)

4. Allowable Methods of Disposal:

   "For all producing wells, adequate provision shall be made to receive all salt water, oil and basic sediment (B.S.) in tub tanks or suitable containers from which all such wastes, tank bottoms, and other petroleum residues shall be discharged into one or more dumps of adequate size, or into equivalent settling devices, equipped with baffles, siphons, or other suitable means to prevent all oil and residues from reaching the water of the Commonwealth." (Quoted from Regulations.)

5. Permit Costs:

   Treatment Plant Permit: $25.00

RHODE ISLAND

No regulating agency (no production).

SOUTH CAROLINA

No regulating agency (no production).

SOUTH DAKOTA

1. Regulating Agency:

   Oil & Gas Board
   State Capitol
   Pierre, South Dakota 57501

2. Publication of Regulations:

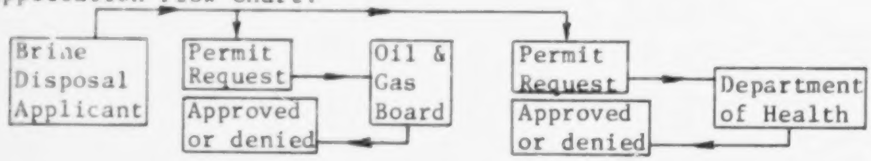
   Out of print.

SOUTH DAKOTA (Cont)

3. Coordinating Agency:

Department of Health
State Capitol
Pierre, South Dakota 57501

4. Application Flow Chart:


Brine Disposal Applicant
Permit Request
Approved or denied
Oil & Gas Board
Permit Request
Approved or denied
Department of Health

Note: An oil well operator, in addition to complying with the regulations of Oil & Gas Board, must also apply for a permit for the discharge of waste from the South Dakota Committee on Water Pollution (Department of Health).

5. Allowable Methods for Disposal:

Present policy is to dispose of brine by evaporation in a properly sealed holding pond. No injection of brine as of March 18, 1971.

6. Costs of Permits: None given.

TENNESSEE

1. Regulating Agency:

State Oil & Gas Board
G-5 State Office Building
Nashville, Tennessee 37219

TENNESSEE (Cont)

2. Publication of Regulations:

Rules & Regulations Pertaining to Oil &
Gas Exploration Adopted by the
State Oil & Gas Board

3. Coordinating Agency:

Department of Health
Division of Stream Pollution
G-5 State Office Building
Nashville, Tennessee 37219

Note: According to the State Oil and Gas Board, there has been no brine for disposal to date.

TEXAS

1. Regulating Agency:

The Railroad Commission of Texas
Oil and Gas Division
Ernest O. Thompson Building
Capitol Station, P.O. Drawer 12967
Austin, Texas 78711

2. Publication of Regulations:

The Railroad Commission of Texas
General Conservation Rules & Regulations
of state wide application, State of Texas
(1971)

TEXAS (Cont)

3. Coordinating Agencies:

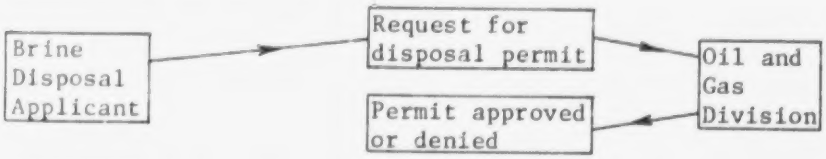
Texas Water Quality Board
1108 Lavaca Street
Austin, Texas 78701

Texas Water Development Board
P.O. Box 12386
Austin, Texas 78711

Texas Parks and Wildlife Department
John H. Reagan Building
Austin, Texas 78701

State Health Department
1100 W. 49th Street
Austin, Texas 78756

4. Application Flow Chart:


Brine Disposal Applicant
Request for disposal permit
Oil and Gas Division
Permit approved or denied

Note: All brine disposal permit applications are processed through the Oil and Gas Division. A majority of the requests are acted on administratively; however, if the request is for an exception to a Statewide Rule, it may be set for public hearing.

5. Allowable Methods of Disposal:

Injection.

No pits.

Discharge into waters off shore and adjacent estuarine zones.

6. Permit Costs:

Permits required but no cost given.

UTAH

1. Regulating Agency:

Division of Oil & Gas Conservation
Department of Natural Resources
1588 West North Temple
Salt Lake City, Utah 84116

2. Publication of Regulations:

The Oil and Gas Conservation Act and
The General Rules and Regulations and
Rules of Practice and Procedure
(1969)

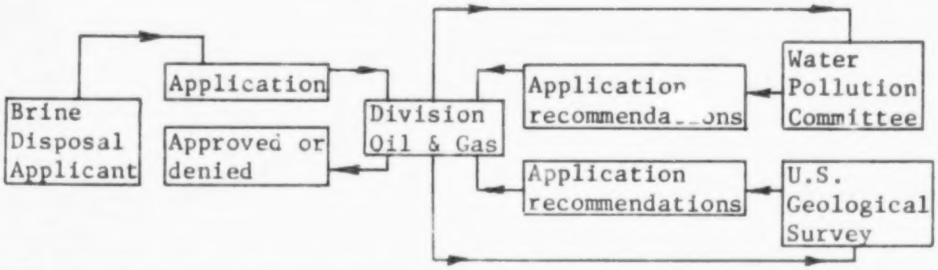
3. Coordinating Agencies:

Utah Water Pollution Committee
Calvin K. Sudweeks, Executive Secretary
44 Medical Drive
Salt Lake City, Utah 84113

U.S. Geological Survey
1588 West North Temple
Salt Lake City, Utah 84116

4. Application Flow Chart:

UTAH (Cont)


Brine Disposal Applicant
Application
Approved or denied
Division Oil & Gas
Application recommendations
Water Pollution Committee
Application recommendations
U.S. Geological Survey

Note: Disposal applications submitted and approved or denied by Division of Oil and Gas Conservation with consideration given to recommendations given by Utah Water Pollution Committee and the U.S. Geological Survey.

5. Allowable Methods of Disposal:

   Injection.

   Pits, lined (in porous soil).

   Pits, unlined (in tight soil).

6. Permit Costs:

   None.

VERMONT

No regulating agency (no production).

VIRGINIA

1. Regulating Agency:

Department of Labor and Industry
Division of Mines and Quarries
Big Stone Gap, Virginia 24219

2. Publication of Regulations:

   Mining Laws of Virginia (Including Oil and Gas)
   Issued by The Department of Labor and Industry
   (1970)

3. Coordinating Agency:

   State Water Control Board
   P.O. Box 11143
   Richmond, Virginia 23230

   There are no rules or regulations covering the disposal of brine.

WASHINGTON

No production

1. Regulating Agency:

   State Oil & Gas Conservation Committee
   Division of Mines & Geology
   General Administration Building
   Olympia, Washington 98501

   Note: The Supervisor of the Division of Mines and Geology of the Department of Natural Resources is also Supervisor for the State Oil and Gas Conservation Committee.

2. Publication of Regulations:

   Department of Natural Resources
   Oil and Gas Rules and Regulations
   (1957)

   No provisions for brine disposal.

WEST VIRGINIA

1. Regulating Agency:

   Department of Mines
   Oil and Gas Division
   P.O. Box 206
   Grantsville, West Virginia

2. Publication of Regulations:

   Oil and Gas Division of the
   Department of Mines
   (1969)

3. Coordinating Agency:

   Department of Natural Resources
   Charleston, West Virginia

4. Allowable Methods of Disposal:

   Injection.

WEST VIRGINIA (Cont)

5. Permit Costs:

   Injection: $100.00.

WISCONSIN

No regulating agency (no production).

WYOMING

1. Regulating Agency:

   Oil and Gas Conservation Commission
   State Oil and Gas Supervisor
   E.S.C. Building
   P.O. Box 2640
   Casper, Wyoming 82601

2. Publication of Regulations:

   Rules and Regulations of Wyoming Oil and Gas Conservation Commission including Rules of Practice and Procedure (1969)

3. Coordinating Agencies:

   Wyoming Department of Health and Social Services
   Division of Health and Medical Services
   Cheyenne, Wyoming 82001

   Wyoming Game and Fish Commission
   Cheyenne, Wyoming

Note: The Wyoming Department of Health and Social Services is concerned with the quality of water in lakes and streams. The Wyoming Game and Fish Commission is also concerned with water quality in lakes and streams and becomes involved in pollution problems when the quality of these waters is threatened.

4. Allowable Methods of Disposal:

   Injection.

   Pits.

5. Permit Costs:

   Injection: $25.

   Pits: $25.

APPENDIX B

SUMMARY OF STATE WATER CONTROL AGENCIES, POWERS, AND PENALTIES

ALABAMA

1. Agency:

   Alabama Water Improvement Commission
   State Office Building
   Montgomery, Alabama 36104

2. Agency Powers:

   a. Develop programs for treatment and disposal of industrial wastes and sewage.

   b. Establish water quality standards.

   c. Receive and examine plans.

   d. Determine permit compliance.

   e. Issue Orders.

3. Penalties:

   $100 to $10,000; also damages for loss or destruction of wild life, aquatic, fish, or marine life.

ALASKA

1. Agency:

   Department of Health and Welfare
   Division of Environmental Health
   Pouch H
   Juneau, Alaska 99801

2. Agency Powers

Jurisdiction to:

a. Abate and prevent pollution.

b. Adopt standards.

c. Issue, modify, or revoke pollution control permits.

3. Penalties:

Up to $25,000 fine and/or up to one year in prison. Also liable up to $100,000 in civil action. Fines for oil discharges from vessels up to $14 million.

ARIZONA

1. Agency:

State Department of Health Division of Water Pollution Control
Hayden Plaza West
4019 No. 33rd Ave.
Phoenix, Arizona 85917

2. Agency Powers:

a. Issue, modify, or revoke orders prohibiting or abating waste discharge into state waters.

b. Require submission of disposal plans and specifications prior to construction.

c. Issue, modify, or revoke orders requiring construction or modification of disposal systems.

d. Adopt remedial measures to abate, prevent, or control pollution.

ARIZONA (Cont)

3. Penalties:

   Injuction, conviction of misdemeanor.

ARKANSAS

1. Agency

   Arkansas Pollution Control Commission
   1100 Harrington Avenue
   Little Rock, Arkansas 72202

2. Agency Powers:

   a. Administer and enforce laws.

   b. Conduct research, investigations, surveys, and studies.

   c. Establish or alter water quality standards.

   d. Require submission of plans and specifications.

   e. Issue or revoke orders and permits.

   f. Adopt rules and regulations.

3. Penalties:

   Misdemeanor. Each day a separate offense.

CALIFORNIA

1. Agency

State Water Resources Control Board
Division of Water Quality, Rooms 1140-1416
9th Street
Sacramento, California 95814

2. Agency Powers:

   a. Adopt water pollution and water quality control plans.

   b. Regulate a new water appropriations to carry out plans.

   c. Review actions of regional boards.

   d. Accept grants.

   e. Conduct research.

   f. Make loans.

3. Penalties:

   Misdemeanor and/or injunctive relief.

COLORADO

1. Agency

   Colorado Department of Health
   Water Pollution Control Commission
   4210 E. 11th Ave.
   Denver, Colorado 80220

2. Agency Powers:

   a. Supervise administration and enforcement of Act.

b. Adopt, modify, and repeal rules and orders.

c. Accept and administer loans and grants.

d. Certify costs and expenditures for pollution control equipment and construction.

e. Hold hearings.

3. Penalties:

$50 to $2,500 per day.

CONNECTICUT

1. Agency:

Water Resources Commission
Room 225
State Office Building
Hartford, Connecticut 06115

2. Agency Powers:

a. Advise, consult, and cooperate with state and federal agencies and industry.

b. Submit prevention and control plans.

c. Conduct studies, investigations, research, and demonstrations.

d. Collect and disseminate information.

e. Issue, revoke or modify orders or permits.

f. Hold hearings.

CONNECTICUT (Cont)

g. Require submission of plans and specifications.

h. Require proper operation and maintenance of disposal systems.

3. Penalties:

$1,000. Each day a separate offense.

DELAWARE

1. Agency:

State of Delaware
Division of Environmental Control
Department of Natural Resources and Environmental Control
P.O. Box 916
Dover, Delaware 19901

2. Agency Powers:

a. Conduct experiments, investigations, research, and studies.

b. Issue general and special orders.

c. Adopt rules and regulations.

d. Make inspections.

e. Enter into agreements.

3. Penalties:

$500 per day of violation. Court stoppage orders.

FLORIDA

1. Agency

Department of Air and Water Pollution Control
Suite 300
Tallahassee Bank Building
315 S. Calhoun Street
Tallahassee, Florida 32301

2. Agency Powers:

   a. Hire necessary personnel.

   b. Accept state monies.

   c. Adopt, modify, and repeal rules and regulations.

   d. Hold hearings.

   e. Establish water standards.

   f. Conduct field studies.

   g. Establish permit system.

   h. Issue orders.

   i. Require construction notice.

   j. Collect and disseminate information.

3. Penalties:

$1,000. Each day a separate offense. Injunctive relief.

GEORGIA

1. Agency:

Georgia Water Quality Control Board
47 Trinity Avenue, S.W.
Atlanta, Georgia 39334

2. Agency Powers:

   a. Establish standards.

   b. Require registration and report filing for operations producing pollution (board).

   c. Accept and administer loans and grants.

   d. Conduct studies, investigations, research, and demonstrations.

   e. Collect and disseminate information.

   f. Issue orders.

   g. Hold hearings.

   h. Require maintenance and operation of abatement systems (department).

3. Penalties:

   Misdemeanor. Each day a violation.

HAWAII

1. Agency:

   Environmental Health Division
   Department of Health
   P.O. Box 3378
   Honolulu, Hawaii 96801

2. Agency Powers:

   a. Enforce water quality standards via a permit system.

   b. Surveillance and monitoring of coastal waters.

3. Penalties:

   $500 and/or one year in prison.

IDAHO

1. Agency:

   Environmental Improvement Division
   Idaho Department of Health
   Statehouse
   Boise, Idaho 83707

2. Agency Powers:

   a. Establish and enforce regulations.

   b. Establish effluent quality standards.

   c. Require inspection and approval of plans.

3. Penalties:

   $1,000 and/or one year in prison. Each day a separate offense.

ILLINOIS

1. Agency

   Environmental Protection Agency
   State of Illinois
   2200 Churchill Road
   Springfield, Illinois 62706

2. Agency Powers:

   a. Enforce state standards.

   b. Assist design engineers.

3. Penalties:

   Fine not to exceed $10,000 for a violation, and additional fine not to exceed $1,000 for each day violation continues.

INDIANA

1. Agency:

   Indiana Stream Pollution Control Board
   1330 W. Michigan Street
   Indianapolis, Indiana 46206

2. Agency Powers:

   a. Establish water quality standards.

   b. Make regulations.

   c. Conduct hearings.

   d. Issue orders.

e. Enforce law.

3. Penalties:

Misdemeanor. $100 and 90 days in jail. Each day $100 extra.

IOWA

1. Agency:

State Department of Health
Lucas State Office Building
Des Moines, Iowa 50319

2. Agency Powers:

   a. Adopt, modify, or repeal reasonable water quality standards.

   b. Hold hearings.

   c. Issue orders.

   d. Direct Health Department to approve plans and specifications and issue permits.

3. Penalties:

Injunction, $100.

KANSAS

1. Agency:

   Environmental Health Services
   Kansas State Department of Health
   5th Floor State Office Building
   Topeka, Kansas 66612

2. Agency Powers:

   a. Revoke permits on 30 days notice.

   b. Adopt water quality standards and regulations.

   c. Unlimited emergency powers.

3. Penalties:

   $25 per day for failure to comply with regulations; $50 to $500 per day for failure to comply with order.

KENTUCKY

1. Agency:

   Legislative Research Commission
   Capitol Building
   Frankfort, Kentucky 40601

2. Agency Powers:

   a. Conduct studies, investigations, research, experiments, and demonstrations.

   b. Establish water quality standards.

   c. Hold hearings.

d. Issue orders.

e. Examine plans and specifications.

f. Inspect construction.

g. Issue, revoke, or modify permits.

h. Examine records.

3. Penalties:

$1,000; value of fish or wildlife killed.

LOUISIANA

1. Agency:

Louisiana Stream Control Commission
P.O. Drawer FC
University Station
Baton Rouge, Louisiana 70803

2. Agency Powers:

a. Set water quality standards.

b. Order or regulate waste discharges.

c. Prohibit discharge.

3. Penalties:

$1,000 and/or up to one year in prison.

MAINE

1. Agency:

Environmental Improvement Commission
State House
Augusta, Maine 04330

2. Agency Powers:

  a. Recommend best use classifications.

  b. Issue permits.

  c. Approve plans.

  d. Enforce legislation.

3. Penalties:

$25 to $1,000 fine each day of violation.

MARYLAND

1. Agency:

Maryland State Department of Health and Mental Hygiene
2305 N. Charles Street
Baltimore, Maryland 21218

2. Agency Powers:

  a. Health Department controls sewage pollution as it affects health.

  b. Department of Water Resources has control of all other sources.

3. Penalties:

$500. $50 each additional day.

MASSACHUSETTS

1. Agency:

Water Resources Commission
Commonwealth of Massachusetts
Division of Water Pollution Control
100 Cambridge Street
Boston, Massachusetts 02202

2. Agency Powers:

Division of Water Pollution Control has joint jurisdiction with Department of Public Health.

3. Penalties:

$100 each day of violation.

MICHIGAN

1. Agency:

Water Resources Commission
Department of Natural Resources
Stevens T. Mason Building
Lansing, Michigan 48926

MICHIGAN (Cont)

2. Agency Powers:
    a. Issue orders and permits.
    b. Restrict new disposal.
    c. Enforce laws.

3. Penalties:

    $500 each day of violation.

MINNESOTA

1. Agency:

    Minnesota Pollution Control Agency
    717 Delaware Street, S.E.
    Minneapolis, Minnesota 55440

2. Agency Powers:
    a. Set water quality and effluent standards.
    b. Inspect plans.
    c. Issue permits.
    d. Enforce compliance.
    e. Issue orders.
    f. Assume municipality powers to construct disposal system and levy taxes.

3. Penalties:

Injunction. $300 or 90 days in jail or both. Each day is a separate offense.

MISSISSIPPI

1. Agency:

Mississippi Air & Water Pollution Control Commission
P.O. Box 827
Jackson, Mississippi 39205

2. Agency Powers:

   a. Enforce rules and regulations.

   b. Accept and administer loans and grants from the federal government.

   c. Conduct studies, research, investigations, and demonstrations.

3. Penalties:

Up to $3,000 and/or one year in prison. Each day a separate violation.

MISSOURI

1. Agency:

Missouri Water Pollution Board
P.O. Box 154
Jefferson City, Missouri 65101

2. Agency Powers:
    a. Issue or restrict permits.
    b. Enforce law.
    c. Issue tax bills for construction.
    d. Seek injunctions.

3. Penalties:

Injunction. $25 to $500 fine. Maximum of $100 per day for continuing violation.

MONTANA

1. Agency:

Water Pollution Control Section
Division of Environmental Sanitation
State Department of Health
Helena, Montana 59601

2. Agency Powers:
    a. Establish standards.
    b. Recommend research and demonstrations.
    c. Direct Board of Health to issue orders.
    d. Holding hearings.
    e. Cause surveys and investigations.

3. Penalties:

Fines up to $1,000 for each day of violation.

NEBRASKA

1. Agency:

Nebraska Water Pollution Control Council
Box 94757
State House Station
Lincoln, Nebraska 68509

2. Agency Powers:

a. Supervise administration and enforcement of pollution control laws.

b. Accept and administer loans and grants.

c. Collect and disseminate information.

d. Conduct studies, investigations, research, and demonstrations.

e. Issue orders and permits.

f. Hold hearings.

g. Require submission of plans and inspect construction.

3. Penalties:

$100 to $500 and $10 each additional day.

NEVADA

1. Agency:

   Department of Health, Welfare and Rehabilitation
   210 S. Fall Street
   Carson City, Nevada 89701

2. Agency Powers:

   a. Approve loans and grants to municipalities from Federal aid.

   b. Adopt and enforce reasonable rules and regulations.

3. Penalties:

   Gross misdemeanor

NEW HAMPSHIRE

1. Agency:

   Water Supply and Pollution Control Commission
   State of New Hampshire
   61 S. Spring Street
   Concord, New Hampshire 03301

2. Agency Powers:

   a. Conduct experiments, investigations, and research.

   b. Require filing of plans and specifications.

   c. Set standards of design and construction.

   d. Monitor pesticides in water.

e. Set up laboratories.

f. Investigate applications for Federal Aid.

3. Penalties:

$1,000 each day of violation

NEW JERSEY

1. Agency

Department of Environmental Protection
P.O. Box 1390
Trenton, New Jersey 08625

2. Agency Powers:

Department of Environmental Protection is responsible for abating all water pollution and maintaining water quality and has broad powers regarding sanitation and sewage disposal.

3. Penalties:

Injunctive relief and various penalties.

NEW MEXICO

1. Agency:

NEW MEXICO (Cont)

New Mexico Water Quality Control Commission
P.O. Box 2348
Sante Fe, New Mexico 87501

2. Agency Powers:

Adopt standards and regulations for pollution prevention.

3. Penalties:

Injunction and fine

NEW YORK

1. Agency:

New York State Department of Health
84 Holland Avenue
Albany, New York 12208

2. Agency Powers:

    a. Hold hearings.
    b. Issue orders.
    c. Issue, extend, deny, revoke, or modify permits.
    d. Conduct investigations.

3. Penalties:

Injunction. Fine of $100 to $500 per day of violation

NORTH CAROLINA

1. Agency:

Water Pollution Control Division
North Carolina Department of Water and Air Resources
P.O. Box 9392
Raleigh, North Carolina 27603

2. Agency Powers:

   a. Issue permits.

   b. Approve plans.

   c. Organize programs.

3. Penalties:

$100 to $1,000. Each day a separate violation.

NORTH DAKOTA

1. Agency:

Division of Water Supply and Pollution Control
North Dakota State Department of Health
Bismarch, North Dakota 58501

2. Agency Powers:

   a. Supervise enforcement of rules and regulations.

   b. Accept and administer loans and grants.

   c. Conduct demonstrations.

d. Collect and disseminate information.

e. Issue, modify, or revoke orders.

f. Hold hearings.

g. Require submission of plans and specifications.

h. Require proper maintenance and operation of disposal system.

3. Penalties:

Injunction, misdemeanor.

OHIO

1. Agency:

Ohio Water Pollution Control Board
P.O. Box 118
Columbus, Ohio 43216

2. Agency Powers:

a. Conduct research, education, and investigation.

b. Enforce programs.

c. Require construction or modification of sewage or waste disposal systems.

d. Suspend construction.

e. Obtain injunctions.

3. Penalties:

   $500 and/or one year imprisonment.

OKLAHOMA

1. Agency:

   Environmental Health Services
   Oklahoma State Department of Health
   3400 North Eastern
   Oklahoma City, Oklahoma 73105

2. Agency Powers:

   a. To prevent or abate water pollution.
   b. Conduct studies investigation, research, and demonstrations.
   c. Adopt rules and regulations.
   d. Accept funds and grants.
   e. Prescribe water criteria.

3. Penalties:

   $500 and/or 90 days in jail. Each day a separate violation.

OREGON

1. Agency:

Oregon State Department of Environmental Quality
State Office Building
1400 S.W. Fifth Avenue
Portland, Oregon 97201

2. Agency Powers:

   a. Formulate rules and regulations.

   b. Conduct studies, investigations, and programs.

   c. Cooperate with other agencies.

   d. Issue orders and hold hearings.

   e. Employ personnel.

3. Penalties:

   Vary, civil or criminal.

PENNSYLVANIA

1. Agency:

   Bureau of Sanitary Engineering
   Pennsylvania Department of Environmental Resources
   P.O. Box 2351
   Harrisburg, Pennsylvania 17120

2. Agency Powers:

   a. Require discharge permits.

   b. Set treatment standards.

3. Penalties:

   $100 to $5,000 plus imprisonment up to one year. Civil penalties: $10,000 plus $500 per day.

RHODE ISLAND

1. Agency:

   Division of Water Supply and Pollution Control
   Rhode Island Department of Health
   335 State Office Building
   Providence, Rhode Island 02903

2. Agency Powers:

   a. Advice, consult, and co-operate with other agencies.
   b. Accept and administer loans and grants.
   c. Conduct studies, investigations, research, and demonstrations.
   d. Collection and disseminate information.
   e. Adopt, modify and repeal water classes and standards.
   f. Hold hearings and issue orders.
   g. Require submission of plans and inspect construction.
   h. Consult advisory board.
   i. Make, amend, and revoke pollution control rules and regulations.
   j Superior court empowered to enforce orders of division.

3. Penalties:

RHODE ISLAND (Cont)

$500 fine and/or 30 days in prison.

SOUTH CAROLINA

1. Agency:

South Carolina Pollution Control Authority
J. Marion Sims Building
Columbia, South Carolina 29201

2. Agency Powers:

a. Require waste sources to meet standards.

b. Act as state agent in Federal Government dealings with water pollution.

c. Perform all necessary acts.

3. Penalties:

$100 to $5,000 and/or one year in prison. Each day a separate violation.

SOUTH DAKOTA

1. Agency:

South Dakota Committee on Water Pollution
State Department of Health
Pierre, South Dakota 57501

SOUTH DAKOTA (Cont)

2. Agency Powers:

   a. Establish Class A and Class B water standards, which can be modified when necessary.

   b. Conduct investigations.

   c. Issue orders.

   d. Instigate hearings.

   e. Issue annual permits upon approval of applications.

3. Penalties:

   $100 and/or one year imprisonment.

TENNESSEE

1. Agency:

   Tennessee Stream Pollution Control Board
   612 Cordell Hull Building
   Nashville, Tennessee 37219

2. Agency Powers:

   a. Establish air quality standards, emission standards, permit system.

   b. Promulgate rules and regulations, hold hearings.

   c. Collect fees.

   d. Require information submission.

3. Penalties:

Misdemeanor, injunctive relief.

TEXAS

1. Agency:

Texas Water Quality Board
1108 Lavaca Street
Austin, Texas 78701

2. Agency Powers:

   a. Establish water quality standards.

   b. Issue and amend permits.

   c. Limit or reduce septic tanks.

   d. Inspect and conduct investigations.

   e. Accept and administer funds.

   f. Enforce Water Quality Act.

   g. Make agreements with Federal agencies.

3. Penalties:

Injunction. Up to $1,000 for each violation or day of violation.

UTAH

1. Agency:

Utah Water Pollution Committee
44 Medical Drive
Salt Lake City, Utah 84113

2. Agency Powers:

   a. Hold hearings.

   b. Review and approve plans.

   c. Issue orders to correct pollution.

   d. Issue permits.

   e. Establish standards.

3. Penalties:

Misdemeanor. Also can be enjoined.

VERMONT

1. Agency:

Vermont Department of Water Resources
State Office Building
Montpelier, Vermont 05602

2. Agency Powers:

   a. Issue orders.

   b. Hold hearings.

- c. Conduct studies, investigations, and demonstrations.
- d. Supervise flood control, channel clearing, and river bank protection.
- e. Adopt, modify, and enforce rules and regulations.
- f. Issue permits.
- g. Administer loans and grants.
- h. Require filing of new construction plans.

3. Penalties:

   $50 each day of violation; up to $1,000 total.

VIRGINIA

1. Agency:

   State Water Control Board
   P.O. Box 11143
   Richmond, Virginia 23230

2. Agency Powers:

   - a. Establish water quality standards.
   - b. Maintain standards.
   - c. Issue orders
   - d. Compel compliance.

3. Penalties:

Injunction. Up to $5,000 fine for each day.

WASHINGTON

1. Agency:

Washington Water Pollution Control Commission
P.O. Box 829
Olympia, Washington 98501

2. Agency Powers:

   a. Approve reports, plans, and specifications for waste treatment facilities.

   b. Issue waste discharge permits.

   c. Administer state and federal construction grants.

   d. Establish basin policy on waste collection, treatment, and discharge.

3. Penalties:

Criminal prosecution; $100 fine each day; recovery of damages incurred; oil discharge penalty, maximum $20,000 fine; full or partial closure of discharger.

WEST VIRGINIA

1. Agency:

WEST VIRGINIA (Cont)

Division of Water Resources
Department of Natural Resources
1201 Greenbriar Street
Charleston, West Virginia 25311

2. Agency Powers:

   a. Issue permits.

   b. Obtain compliance.

   c. Institute criminal proceedings.

3. Penalties:

   Violation, $100 to $1,000; willful violation, $1,000 to $10,000. Also up to 6 months prison.

WINCONSIN

1. Agency:

   Division of Environmental Protection
   Department of Natural Resources
   P.O. Box 450
   Madison, Wisconsin 53701

2. Agency Powers:

   a. Monitor surface water quality.

   b. Conduct stream surveys.

   c. Hold hearings.

   d. Issue orders.

e. Approve plans.

f. Disburse state and Federal aid.

g. Issue licenses and permits.

3. Penalties:

Up to $5,000 each day of violation.

WYOMING

1. Agency:

Division of Health and Medical Services
Wyoming Department of Health and Social Services
State Office Building
Cheyenne, Wyoming 82001

2. Agency Powers:

a. Suggest to, advise, and assist the council.

b. Conduct and supervise studies, investigations, and research.

c. Require consultations and approval of plans prior to construction of waste treatment facilities.

3. Penalties:

Up to $1,000.

APPENDIX C

LABORATORY TESTS

Chemical Lab Tests (ppm and meq/l)

1. Total dissolved solids
2. Total solids
3. Organic solids
4. Iron Oxide (FeO)
5. Iron Sulfide ($FeSO_4$)
6. Calcium Carbonate ($CaCO_3$)
7. Silica (Si)
8. Barium Sulfate ($BaSO_4$)
9. Carbonate ($CO_3^=$)
10. Bicarbonate (HCO_3^-)
11. Sulfate ($SO_4^=$)
12. Chloride (Cl^-)
13. Calcium (Ca^{++})
14. Magnesium (Mg^{++})
15. Sodium (Na^+)
16. Barium (Ba^{++})
17. Dissolved iron
18. pH
19. Hydrogen Sulfide (H_2S)
20. Specific gravity
21. Oil content (ppm)

Other Tests (ppm and meq/l)

1. Dissolved Oxygen (DO)
2. Free carbon dioxide (CO_2)
3. Turbidity
4. Bacteria
5. Chlorine residual if chlorine used as a bacteriacide

Not all of these tests are required on all oilfield brines which are to be disposed of. Exactly which tests should be run depends primarily on the type of disposal mechanism and the requirements of Oil Regulating Agencies and Water Quality Agencies.

APPENDIX D

ANALYSES FORMULA DEVELOPMENT

The progression of calculations used in the disposal mechanism analysis is lengthy but relatively simple.

Initial information which should be obtained includes the following. (A more thorough explanation can be found in any college level fluid mechanics book.)

General

X_i = Flow rate per well in gallons per day (gpd).

Y = Life of project in years (yrs).

D = Outside diameter of pipe (ft).

ρ = Density of fluid (lb/ft^3).

μ = Viscosity of the fluid (lb_m/ft-sec).

Force due to gravity:

g_c = Constant

$$32.17 \frac{\text{pounds mass-foot}}{\text{pounds force-second}^2}.$$

FL = Pressure loss due to friction (psi).
(assume 0.003 psi per foot of pipe)

SG = Specific gravity.

Injection

r_w = Radius of the well bore (ft).

k = Average formation permeability (darcies).

h = Effective height of the formation face (ft).

ϕ = Average formation porosity as a decimal fraction; volume of voids divided by total volume.

P_r = Reservoir pressure (psi).

P_b = Bottom hole pressure; pressure at the bottom of the well (psi).

The following relationships should be developed to accompany these basic facts.

Pipe Diameter, d

d = Inside diameter of pipe in inches.

W = Fluid flow rate in thousands of pounds per hour (lb_m/hr)

ρ = Density of the fluid (lb_m/ft^3)

Assume: $\rho = 62.5\ lb_m/ft^3$

Note: Koenig.[47] Pure water may be used because fluid density is not a major factor in injection.

$$d = \frac{2.2W^{.45}}{(\rho)^{.31}}$$

$$X_i = \text{Gallons per day} = W\left(\frac{lb_m}{hr}\right)\left(\frac{24\ hr}{day}\right)\left(\frac{1\ ft^3}{62.5\ lb_m}\right)\left(\frac{7.48\ gal}{ft^3}\right)$$

$$X_i = (2.87)(10^3)(W)$$

$$W = \frac{X_i}{2.87}$$

$$d = (.6)\ \frac{(W)}{1000}^{.45} = 0.6\left[\frac{X}{(2.87)(10^3)}\right]^{0.45}$$

$$d = \frac{2.2X_i^{.45}}{(3.6)(35.9)} = (1.7)(10^{-2})\ (X_i^{.45})$$

Fluid Velocity, V

A = Cross section area of pipe (ft^2); r = Pipe radius (ft);

Q = Volume flow rate (ft^3/sec); d (in.) and D (ft) = pipe diameter.

$$Q\left(\frac{ft^3}{sec}\right) = A\ (ft^2)\ V\left(\frac{ft}{sec}\right)$$

$$Q\left(\frac{ft^3}{sec}\right) = X_i\left(\frac{gal}{day}\right)\left(\frac{1\ day}{86400\ sec}\right)\left(\frac{1\ ft^3}{7.48\ gal}\right)$$

$$\frac{X_i}{(86400)(7.48)}\left(\frac{ft^3}{sec}\right) = \pi r^2\ (ft^2)\ V\left(\frac{ft}{sec}\right)$$

$$V\left(\frac{ft}{sec}\right)\quad \frac{X_i\ \ (ft^3)}{(86400)\ \ (7.48)(3.14)r^2(ft^2)(sec)}$$

$r = \frac{D}{2}$ = Radius of pipe

$$D = \frac{d}{12}$$

$$r = \frac{d}{24}$$

and $\quad r^2 = \frac{d^2}{576}$

then $\quad V = \frac{576}{(86400)(7.48)(3.14)}\left(\frac{X_i}{d^2}\right)$

and $\quad V = (2.84)\ (10^{-4})\left(\frac{X_i}{d^2}\right)$

Injection

Fluid radius, r_e, at end of project life (Y).

r_e = Fluid radius (extent of injected fluid from well assuming homogeneous formation and fluid dispersion into formation in the shape of a cylinder of height, h, and radius, r_e).

Y = Project life (years).

X = Flow rate per well (gpd).

h = Formation height (ft).

ϕ = Formation porosity (decimal fraction).

Vol = Volume injected over project life

$$= \frac{365}{7.48}(X_i)(Y) = 48.8\,(X_i)(Y)$$

Vol_1 = Volume of void space in formation = $(\pi)(r_e^2)(h)(\phi)$ = Vol

$$r_e^2 = \left[\frac{48.8}{\pi}\right]\frac{(X_i)(Y)}{(h)(\phi)}$$

$$r_e = \left[\frac{48800}{\pi}\right]^{1/2}\left[\frac{(X_i)(Y)}{(1000)(h)(\phi)}\right]^{1/2}$$

$$r_e = (124.6)\left[\frac{(X_i)(Y)}{(1000)(h)(\phi)}\right]^{1/2}$$

Reynold's Number

$$N_{re} = \frac{VD}{\nu} = \frac{VD\rho}{\mu};\quad D = \frac{d}{12}$$

Assume: $\rho = 62.5\left(\frac{1b_m}{ft^3}\right)$ and $\mu = 1$ centipoise $= \frac{1\ 1b_m}{1488(\text{ft-sec})}$,

then $N_{re} = \frac{(1488)(62.5)}{12}\ \frac{(V)(d)(S.G.)}{\mu}$

and $N_{re} = (7.75)(10^3)\ \frac{(d)(V)(S.G.)}{\mu}$ or $2.201\left(\frac{X_i}{d}\right)\left(\frac{S.G.}{\mu}\right)$

f = Fluid friction factor = function of N_{re} obtained using Moody Diagram (see fluid mechanics text).

Friction Loss, P_f (psi)

H_f = Head loss due to friction = $\frac{2fLV^2}{g_c D}$;

but P_f = Pressure loss due to friction = $\frac{(H_f)\rho i}{144}$ and $D = \frac{d}{12}$

$$\text{so } P_f = \frac{2fLV^2}{g_c d}\left[\frac{12\rho}{144}\right] = \frac{fL\rho V^2}{193.02(d)}$$

Assuming: ρ = Pure water density (negligible effect on overall analysis) = 62.5, then

$$P_f\ (\text{psi}) = \frac{2(12)(62.5)}{(32.17)(144)}\ \frac{fLV^2}{d}$$

and $P_f = 32.36\ (10^{-2})(fLV^2/d)$.

Driving Pressure, P_d (psi)

X_i = Fluid flow rate through the formation (gpm).

K = Formation permeability (darcies).

A = Area of the formation face perpendicular to the direction of flow (ft^2).

μ = Fluid viscosity (centipoise).

I = Injection pressure gradient (ratio of the difference) in pressure between the bottom hole and reservoir pressure to the difference in distance between the fluid radius and well bore radius).

$$X_i = \frac{KIA}{\mu}$$

$$X_i = \frac{K}{\mu}\left[\frac{P_b - P_r}{r_e - r_w}\right] 2\pi rh$$

$$X_i = \frac{K}{\mu}\left[\frac{\Delta P}{\Delta r}\right] 2\pi rh$$

$$X_i \left(\frac{\Delta r}{r}\right) = \frac{2\pi hk}{\mu}(\Delta P)$$

$$X_i \int_{r_w}^{r_e} \frac{dr}{r} = \frac{2\pi hk}{\mu} \int_{P_r}^{P_b} dp$$

$$X_i \, \mathrm{In}\left(\frac{r_e}{r_w}\right) = P_d \left(\frac{2\pi hk}{\mu}\right)$$

$$P_d = \frac{X_i \mu \, \mathrm{In}\left(\frac{r_e}{r_w}\right)}{2\pi hk}$$

$$K = 1 \text{ darcy} = \frac{1(cp)(cm^2)}{(sec)(atm)}$$

$$1\ (cm^2) = .001076\ ft^2$$

$$1 \text{ atm} = 14.7 \, \frac{\text{lb}_f}{\text{in}^2}$$

$$1 \text{ darcy} = (4.92)(10^{-8}) \, \frac{\text{lb}_m\text{-ft-in}^2}{\text{lb}_f\text{-sec}}$$

Substituting:

$$P_d = \left(X_i\right)\left(\frac{\text{gal}}{\text{day}}\right)\left(\mu\right)\left(\frac{\text{lb}_m}{1488 \text{ ft-sec}}\right) \frac{2.303 \log\left(\frac{r_e}{r_w}\right)(\text{lb}_f\text{-sec}^2)}{(2)(3.14)(h)(\text{ft})(K)(4.92)(10^{-8})(\text{lb}_m)(\text{ft})(\text{in}^2)}$$

$$= (7.75)(10^{-3}) \left[\frac{X_i \mu \log}{hk}\left(\frac{r_e}{r_w}\right)\right].$$

Let μ= 1 centipoise,

$$\text{then } P_d = \frac{X_i \log\left(\frac{r_e}{r_w}\right)}{(128.9)(K)(h)}$$

Static Pressure (Constant), P_c (psi)

$$P_c \, (\text{lb}_f / \text{in}^2) = \frac{\rho L g}{g_c} .$$

Assume: $\rho = \left(62.5 \, \frac{\text{lb}_m}{\text{ft}^3}\right)$ (S.G.) and $g = 32.17 \left(\frac{\text{ft}}{\text{sec}^2}\right)$

$$P_c = \frac{(62.5 \text{ lb}_m)(L)(\text{ft})(32.17)(\text{ft})(\text{lb}_f\text{-sec}^2)(1)(\text{ft}^2)\text{ (S.G.)}}{(\text{ft}^3)(\text{sec}^2)(32.17)(\text{lb}_m\text{-ft})(144)(\text{in}^2)}$$

$$P_c = \frac{(62.5)(L)}{144} \; \frac{(\text{lb}_f) \text{ (S.G.)}}{\text{in}^2}$$

$$P_c = (0.434)(L)\ \frac{lb_f}{in^2}\ (S.G.) = \frac{\rho L}{144}$$

Wellhead Pressure, P_{ch}(psi)

P_{ch} = Wellhead pressure = pressure at the top of the well = $P_b + P_f - P_c$.

Note: P_{ch} may also be thought of as a change in the pressure head to be supplied by the pump. That is, both P_b and P_f must be overcome if the fluid is to flow in the pipe. Therefore, if $P_b + P_f - P_c$ is negative, no pressure must be supplied by pumping. If $P_b + P_f - P_c$ is positive, the combined resistence to flow of the reservoir exceed the pressure head of weight of the fluid column in the tube, and pumps must be supplied to drive water into the receiving formation.

$P_{ch} = P_b + P_f - P_c$,

but $P_b = P_d + P_r$;

therefore, $P_{ch} = P_d + P_r + P_f - P_c$.

Hydraulic Horsepower

$P_p = P_{ch} + FL$

P_p = Pump discharge pressure = Change in pressure head (P_{ch} in psi) + FL (in psi)(pipeline pressure loss due to friction)

$$\text{HHP} = \text{Hydraulic Horsepower} = \frac{(P_p)(X_i)(144)}{(550)(7.48)(86400)}$$

$$\text{HHP} = \frac{(P_p)\ (X_i)}{(2.468)(10^6)}\ .$$

Brake Horsepower

$$\text{BHP} = \text{Brake Horsepower} = \frac{\text{Hydraulic Horsepower}}{\text{Pump Efficiency}}$$

(Assume a pump efficiency of .85)

$$\text{BHP} = \frac{\text{HHP}}{.85}\ .$$

Kilowatts

$$\text{KW} = \text{Kilowatts} = \frac{(\text{Brake Horsepower})(.7457\ \text{kw/hp})}{\text{motor efficiency}}.$$

(Assume a motor efficiency of .93)

$$\text{KW} = \frac{(\text{BHP})(.7457)}{.93}\quad (\text{BHP})\ (.802)$$

$$\text{KW} = (\text{HHP})\ (.943).$$

Pump Capacity

$$\text{GPM} = X_i \frac{\text{gallons}}{\text{day}} \times \frac{1\ \text{day}}{1440\ (\text{minute})}\ .$$

$$\text{GPM} = \frac{X_1}{1440}\ .$$

Right-of-Way Cost

$$\$/\text{ft} = (\text{cost per acre})\left(\frac{\$}{\text{acre}}\right)\left(\frac{1\ \text{acre}}{43560\ \text{ft}^2}\right)(\text{Right-of-way width})(\text{ft}).$$

Assume: $109 per acre and 30 ft right-of-way width,

$$\text{then } \$\text{foot} = \frac{(109)(30)}{43560} = .075.$$

APPENDIX E

COMPUTER PROGRAM FOR DISPOSAL BY INJECTION, EVAPORATION. DIRECT DISCHARGE (PRICING FOR ALL-NEW EQUIPMENT)[58, 59]

The computer program follows the previously given hand calculation disposal system analysis very closely; however, a few major factors differ. The hand calculation scheme has sufficient flexibility that: it may be used for new or converted injection systems; any piping may be used with any suitable pump merely by substituting design and cost values for the equipment (including '0' if the equipment is not used); and up-to-date prices can be used.

The computer only takes specific information (i.e., instead of up-to-date pipe costs, introduce the RRC code (Region Rating Code, Table 15) of the state in which the drilling will be done and the computer will assign the costs from tables already in the program for appropriate 9" diameter J-55 or N-80 pipe). Also, some of the costs must be updated by referring to the Engineering News Record Building Cost Index (ENRBCI in program is 570 for 1962). Cost updating must be read into the computer. The program only calculates the cost of an all new system.

Input

The operator has the option of selecting any combination of disposal

Table 15. RRC ZONES[68]

Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
Louisiana	Florida	Wyoming	Pennsylvania	Utah	Montana
Mississippi	Arizona	West Texas	New York	Nevada	Michigan
Southwest Texas	New Mexico	Panhandle Texas	West Virginia		Oklahoma
Gulf Texas	California	Colorado	Ohio		Arkansas
North Central Texas	South Dakota		Virginia		Illinois
North Dakota			Nebraska		Kentucky
Kansas			Indiana		
			East Texas		
			Alabama		

configurations he wishes using the first input card. This program card calls the desired disposal system. If more than one disposal system is desired, the operator simply enters additional program call cards in the order in which he wishes to look at the prospective disposal system(s). Following the first program call card, the data for the specific disposal system is put into the computer.

Program Call Card

The program call card contains combinations of the numbers 1, 2, and 3 followed by a decimal point. The number 1. in any two columns of columns 1-10 calls the injection program. If the number 2. is entered in any two columns of columns 11-20, the evaporation program is called. The number 3. in any two columns of columns 21-30 calls the conveyance or direct discharge model.

Once the program call card starts a particular disposal system, the computer will calculate as many different configurations as desired; however, the computer operator must enter all the data necessary for each different configuration.

Data Cards

The specific data array of each program follows, but a brief introductory explanation is necessary. For any disposal program to work, all the data required by the program must be inputted. Even if only a slight change is made in a variable value of a disposal method, all the data necessary for the new configuration must be printed on a data card because the computer saves no data from one system to the next. The last number in the last data card of each different type of disposal system must be the number 1 to designate the completion of the particular disposal system input (injection and evaporation are different types of disposal systems; injection_1 and injection_2 are different configurations of the same disposal system) in the ten data columns following those columns containing disposal system data.

Data Deck

1. Program call card with a 1. in columns 1-10, a 2. in columns 11-20, and/or a 3. in columns 21-30.
2. Injection data requires two data cards per injection configuration in addition to and following the program call card, for a total of at least three cards. A "1." must be placed anywhere in the reserved ten columns after the value of the last variable, EL, in the final injection system configuration data card. (Note, F 10.0)
3. Evaporation requires three data cards per evaporation configuration in addition to and following the program call card for a total of at least four cards. A "1." must be placed after the value of the last variable, BCI, in the final evaporation system configuration data card. (Note, F 10.0)

4. Conveyance also requires three data cards per configuration in addition to and following the program call card for a total of at least four cards. A "1." must be placed after the value of the last variable, Y, in the final conveyance system configuration. (Note, F 10.0)

Variables

1. Injection[54]

Variable	Format	Description
a. JC	13	Job code; number configurations.
b. PLACE (I)	10A1	Location name.
c. RRC	A2	Regional Rating Code; state number.
d. XO	F5.3	Total daily volume to be injected, Kgd (thousands of gallons per day).
e. RKW	F3.3	Cost of electrical power, \$/KWH.
f. CPA	F4.0	Cost of land for pump station, injection well, and connecting distribution pipe, \$/acre.
g. Y	I2	Estimated project life, years.
h. II	F4.3	Interest or discount rate, decimal fraction.
i. ENR	F3.0	Current Year Engineering News Record Building Cost Index, necessary to update cost values already in computer (ENRBCI = 570)$_{1962}$
j. LI	I1	Lithology - type of completion 0 (zero) indicates closed hole required; 1 indicates open hole.

Variable	Format	Description
k. L	F5.0	Total depth of well, feet.
l. H	F3.0	Effective height of injection zone, feet.
m. PHI	F2.2	Formation porosity, decimal fraction.
n. PK	F4.3	Formation permeability, darcies.
o. PR	F4.0	Reservoir pressure, psi.
p. D	F3.2	Inside diameter of injection conduit, inches.
q. COR1	F4.1.	Drilling correction cost term (allows for hole sizes other than standard 9 inches).
r. VCPIPE	F3.2	Fluid viscosity of brine, centipoise.
s. VCFORM	F3.2	Fluid viscosity of brine, centipoise.
t. SPGR	F2.1	Specific gravity of brine.
u. PCHTF	F3.2	Maximum casing head pressure test factor, psi/ft.
v. XP	F5.0	Oil flow, Kgd.
w. DPM	F4.0	Distance from collection point to well, miles.
x. EL	F4.0	Elevation of well below (+) or above (-) brine collection point, feet.
y. X LAST	F10.0	Write 1. at end of last configuration data card.

2. Evaporation[52]

Variable	Format	Description
a. XO	F10.3	Brine flow, Kgd.

Variable	Format	Description
b. XW	F10.3	Oil flow, Kgd.
c. CE	F10.3	Brine concentration, ppm.
d. PREC	F10.3	Precipitation, inches/year.
e. EO	F10.3	Evaporation rate (gross), inches/year.
f. FF	F10.3	Distance from collection point to pond, miles.
g. EL	F10.3	Elevation of pond below (+) or above (-) brine collection point, feet.
h. ECU	F10.3	Power cost, $/KWH.
i. CLU	F10.3	Land cost, $/acre.
j. I	F10.3	Capital discount rate or interest, decimal fraction.
k. Y	F10.3	Project life, years.
l. BCI	F10.3	Current Year Engineering News Record Building Cost Index.
m. X LAST	F10.0	Write 1. at end of last configuration data set.

3. Conveyance (Direct Discharge)[52]

Variable	Format	Description
a. XO	F10.2	Brine flow, Kgd.
b. XW	F10.2	Oil product flow, Kgd.
c. FF	F10.3	Distance from brine collection point to discharge, miles.
d. EL	F10.2	Elevation of discharge below (+) or above (-) collection point, feet.
e. ECU	F10.2	Power cost $/KWH.

Variable	Format	Description
f. ZI	F10.2	Capital discount rate or interest, decimal fraction.
g. BCI	F10.2	Current Year Engineering News Record Building Cost Index.
h. Y	F10.4	Project life, years.
i. X LAST	F10.0	Write 1. at end of last configuration data set.

Program Quirks and Limitations

1. Injection. Disregard Product Petrol Concentration, ppm, in printout.
2. Evaporation. Printout of capital investment for evaporation pond only, not entire system.
3. Computer program relationships only good for daily brine flow greater than 1,000 barrels per day.
4. Treatment capital and operating costs taken from Figures 23 and 24.

Regional Rating Code (RRC) Zones

The Regional Rating Code divides the continental United States (excluding Alaska and Hawaii) into six zones by average drilling costs per zone as reported in Joint Association Survey of Industrial Drilling Costs (Section 1), 1962. An adjustment has been made for states having predominently shallow, cheaper wells. RRC zones are given in Table 15.

Of note is the variable, COR 1 F4. 1, in the injection program. Certainly drilling and development expenses in either a production or development well are highly dependent on the diameter of the well bore. While hand calculations allow individual size allocations with regard to well diameter, the computer does not, directly. Rather, an expression relating cost with diameter and depth developed by Koenig and others is used to express well diameter and drilling costs in terms of a standard well; in effect, a common denominator. A statistical analysis of oilwell diameter performed by Koenig[47] revealed that the most common weighted production hole diameter (WPHD) was 9 inches. This computer program uses the previously mentioned standard types of pipes with diameters of 9 inches. Therefore, the COR 1 value must be calculated for each drilling situation to adjust for actual WPHD diameters. If a 9-inch diameter is used, the value entered will not be an adjusted value.

To arrive at the appropriate drilling cost adjustment for well diameter, the first step is to calculate the weighted production hole diameter, WPHD (because often the surface casing is larger in diameter than the production or bottom hole diameter)[54].

$$\text{WPHD} = \frac{N(\text{SHD}) + (10 - N)(\text{BHD})}{10}$$

Where WPHD = Weighted production hole diameter (inches).

$N = \frac{L^1}{L} \times 10$ = Fraction of total depth which surface casing extends.

L = Total depth of the well (feet).

L^1 = Depth to which surface casing is set (feet).

BHD = Bottom hole diameter (inches).

SHD = Surface hole diameter (inches).

Using the value obtained the next step is to read, from Table 16 the Koenig Index corresponding to the weighted production hole diameter (WPHD):

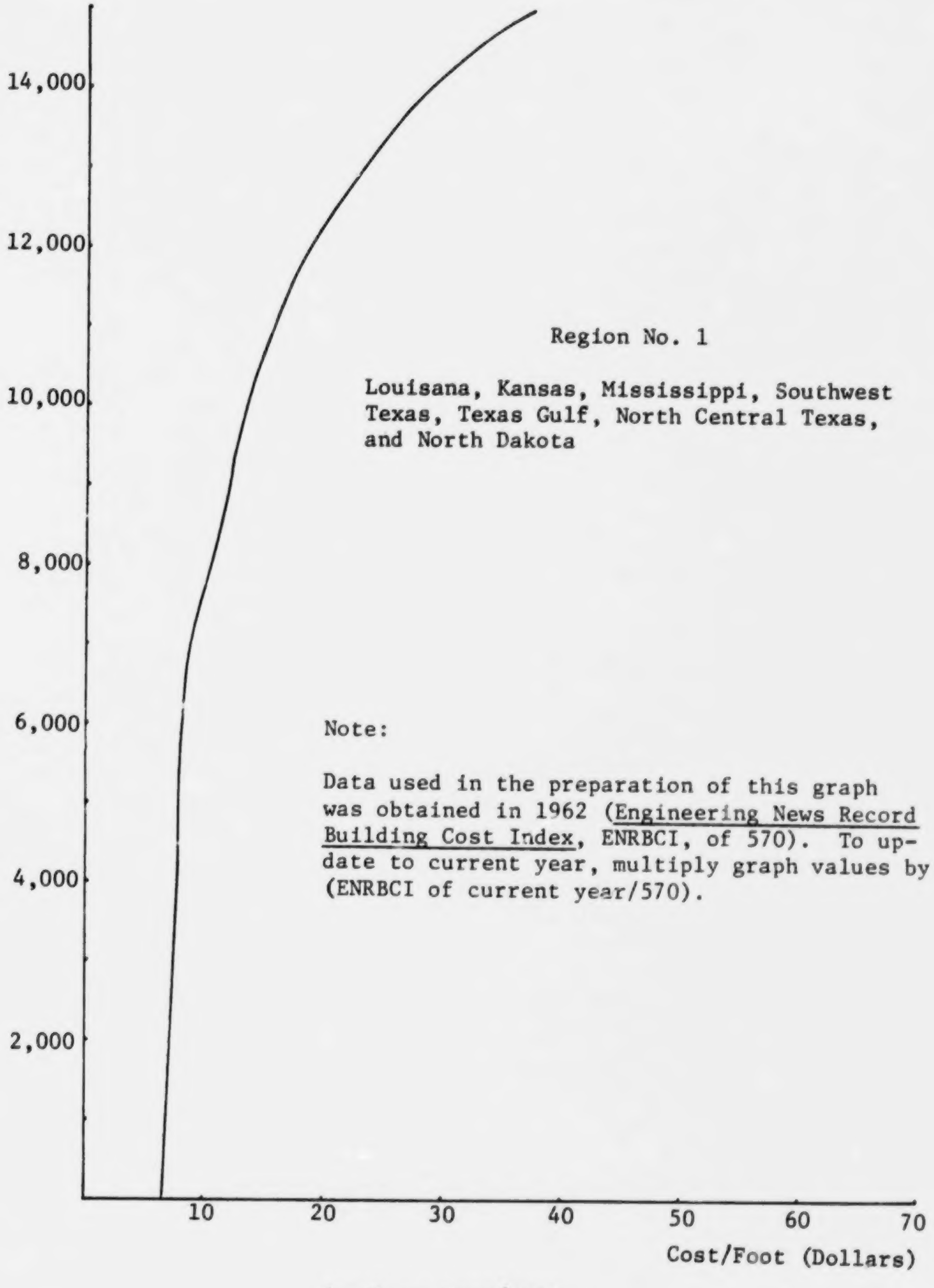
Table 16. WELL COST VARIATION WITH HOLE DIAMETER[47, 54]

Bit Size (Inches)	Koenig Index (ft)
6 3/4	88.5
7 3/8	91.5
7 5/8	93.1
7 3/4	93.9
7 7/8	94.5
8 1/2	98.5
8 5/8	98.8
8 3/4	99.3
9	100
9 5/8	112.3
9 7/8	117.5
10 5/8	131
11	143
12	172
12 1/4	180
12 3/4	226
15	250
17 1/2	292

From Table 15, obtain the Regional Rating Code number of the well. Look up the cost ($/foot) of drilling at the depth desired in the appropriate RRC Graph (Figures 23 through 28), and multiply this value by the well depth. This value is the drilling cost of a 9-inch diameter well (D_9) and should be expressed in thousands of dollars (K dollars).

To calculate the COR 1 value (in K dollars), use the formula:

$$\text{Drilling Cost}_{(\text{COR } 1)} = (\text{Drill Cost}_9 \times \frac{\text{Koenig Index}}{100}).$$



Region No. 1

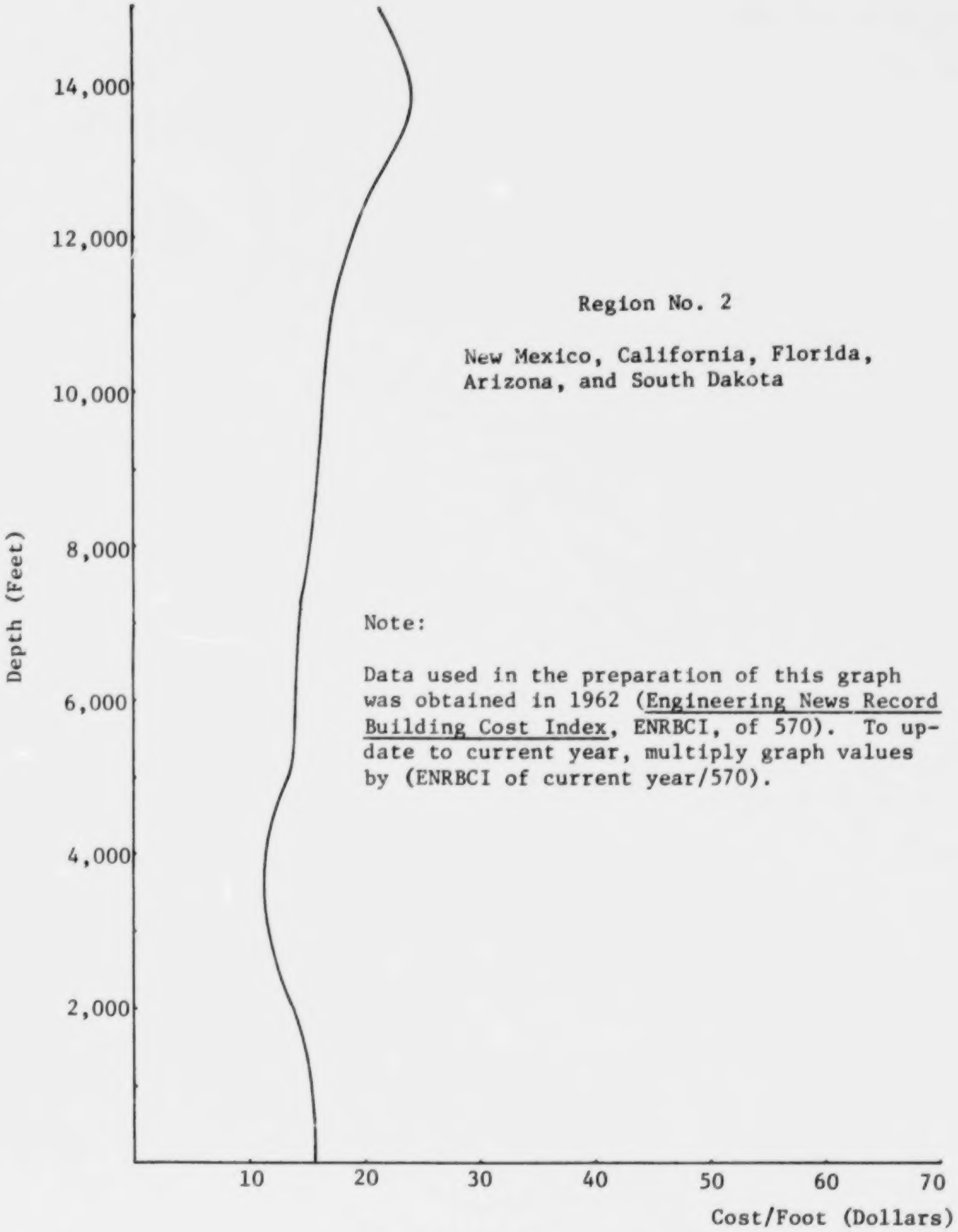
Louisana, Kansas, Mississippi, Southwest Texas, Texas Gulf, North Central Texas, and North Dakota

Note:

Data used in the preparation of this graph was obtained in 1962 (Engineering News Record Building Cost Index, ENRBCI, of 570). To update to current year, multiply graph values by (ENRBCI of current year/570).

Depth vs Cost/Foot

Figure 23. Region Rating Code 1.[68]



Region No. 2

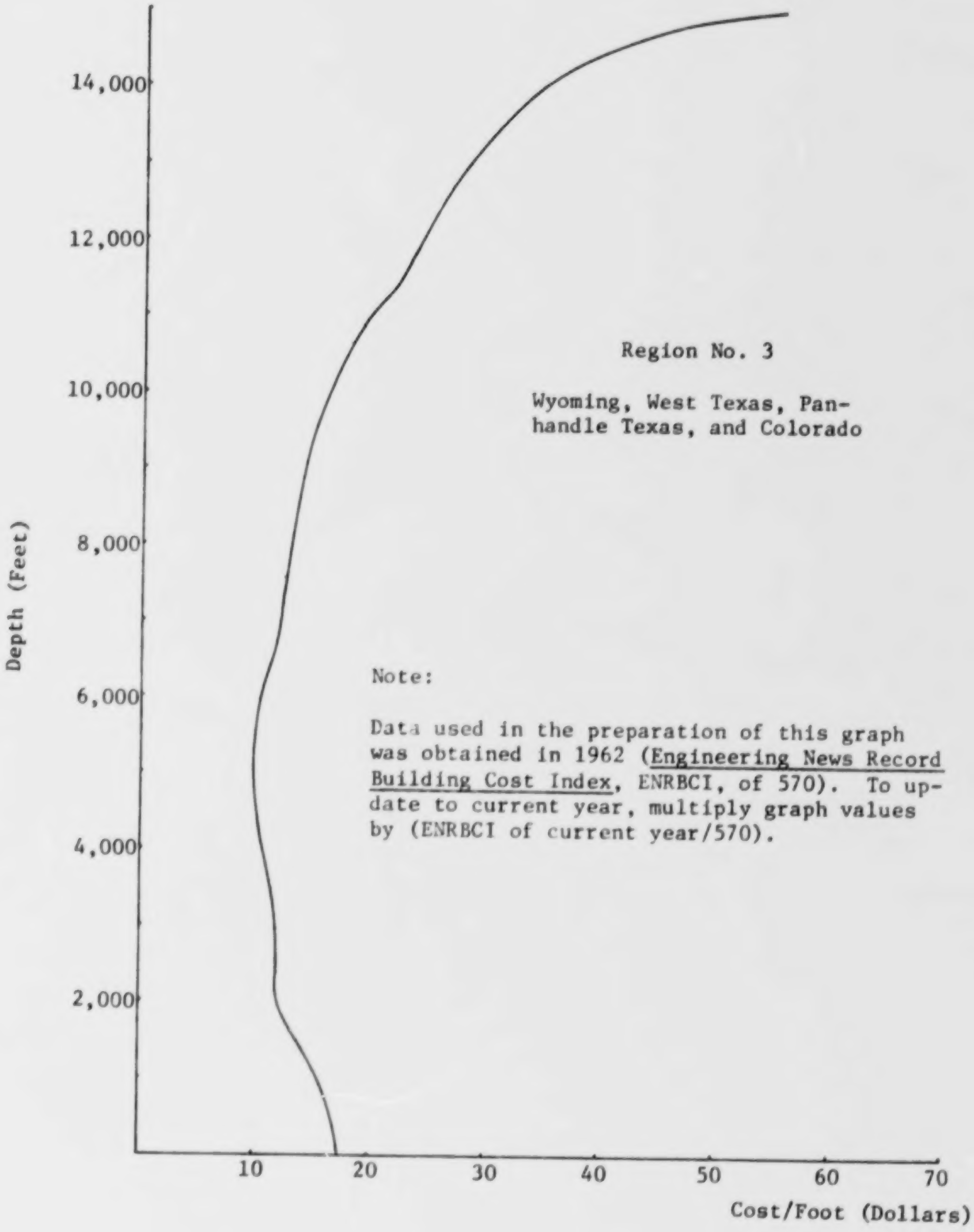
New Mexico, California, Florida,
Arizona, and South Dakota

Note:

Data used in the preparation of this graph was obtained in 1962 (Engineering News Record Building Cost Index, ENRBCI, of 570). To update to current year, multiply graph values by (ENRBCI of current year/570).

Depth vs Cost/Foot

Figure 24. Region Rating Code 2.[68]



Region No. 3

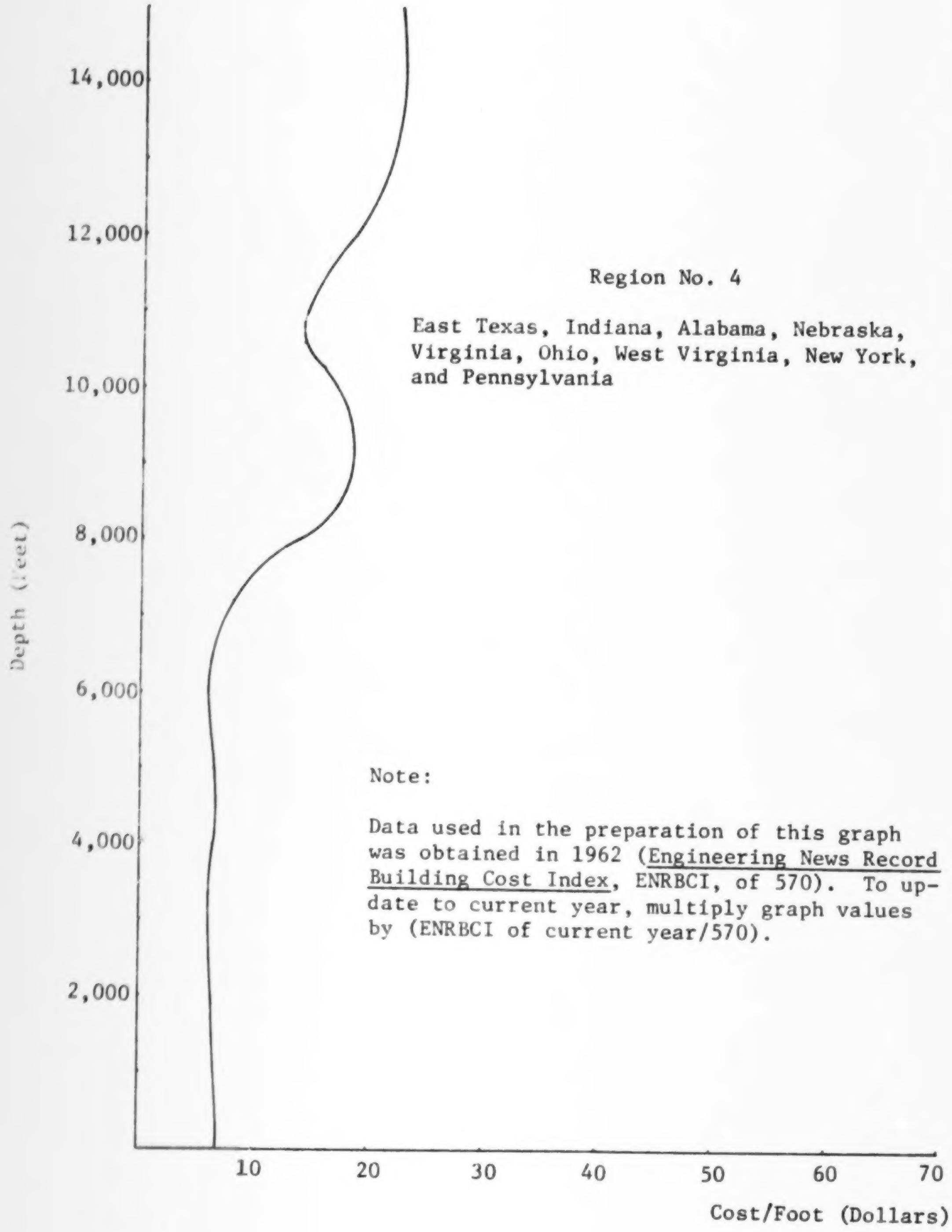
Wyoming, West Texas, Panhandle Texas, and Colorado

Note:

Data used in the preparation of this graph was obtained in 1962 (Engineering News Record Building Cost Index, ENRBCI, of 570). To update to current year, multiply graph values by (ENRBCI of current year/570).

Depth vs Cost/Foot

Figure 25. Region Rating Code 3.[68]



Region No. 4

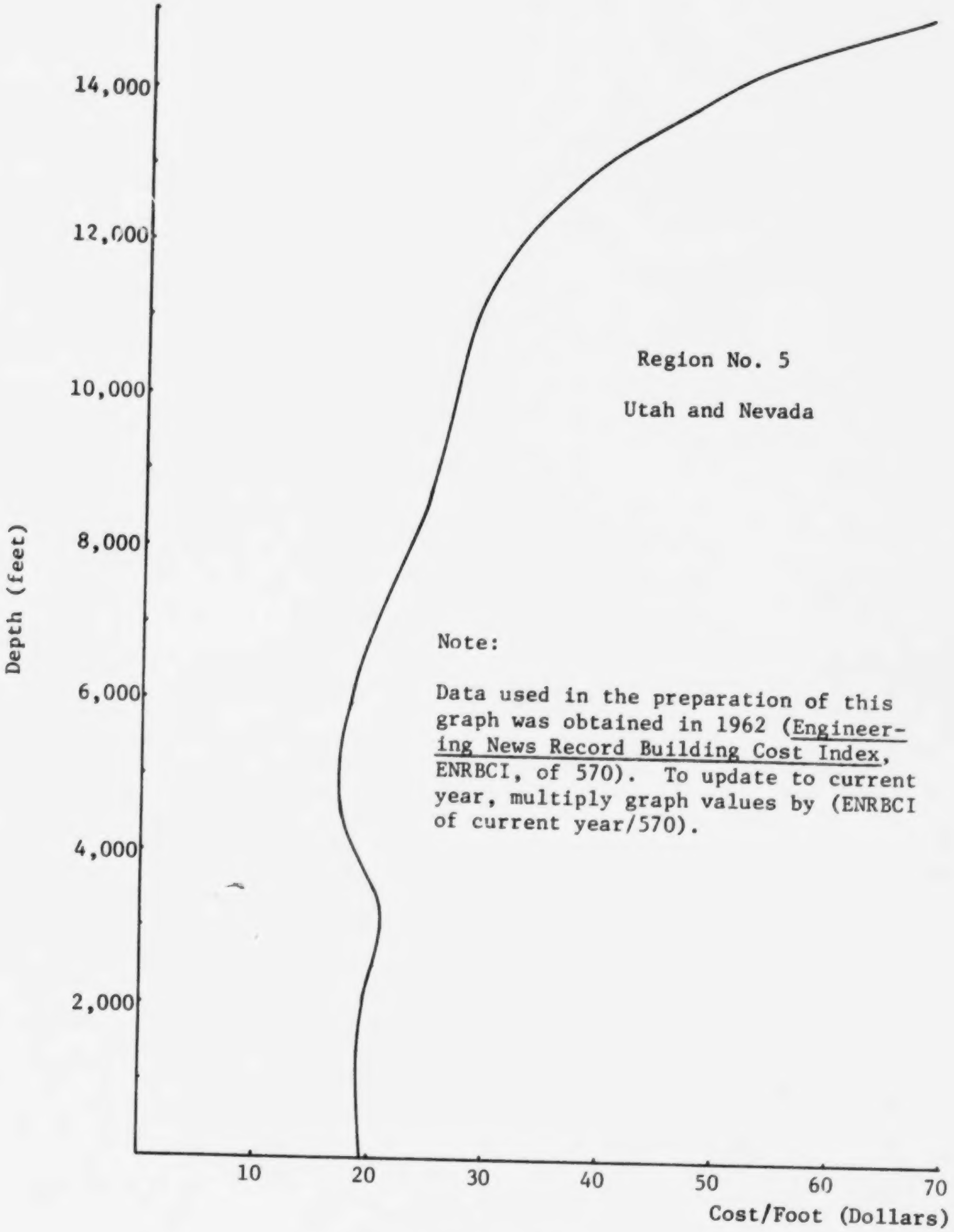
East Texas, Indiana, Alabama, Nebraska, Virginia, Ohio, West Virginia, New York, and Pennsylvania

Note:

Data used in the preparation of this graph was obtained in 1962 (Engineering News Record Building Cost Index, ENRBCI, of 570). To update to current year, multiply graph values by (ENRBCI of current year/570).

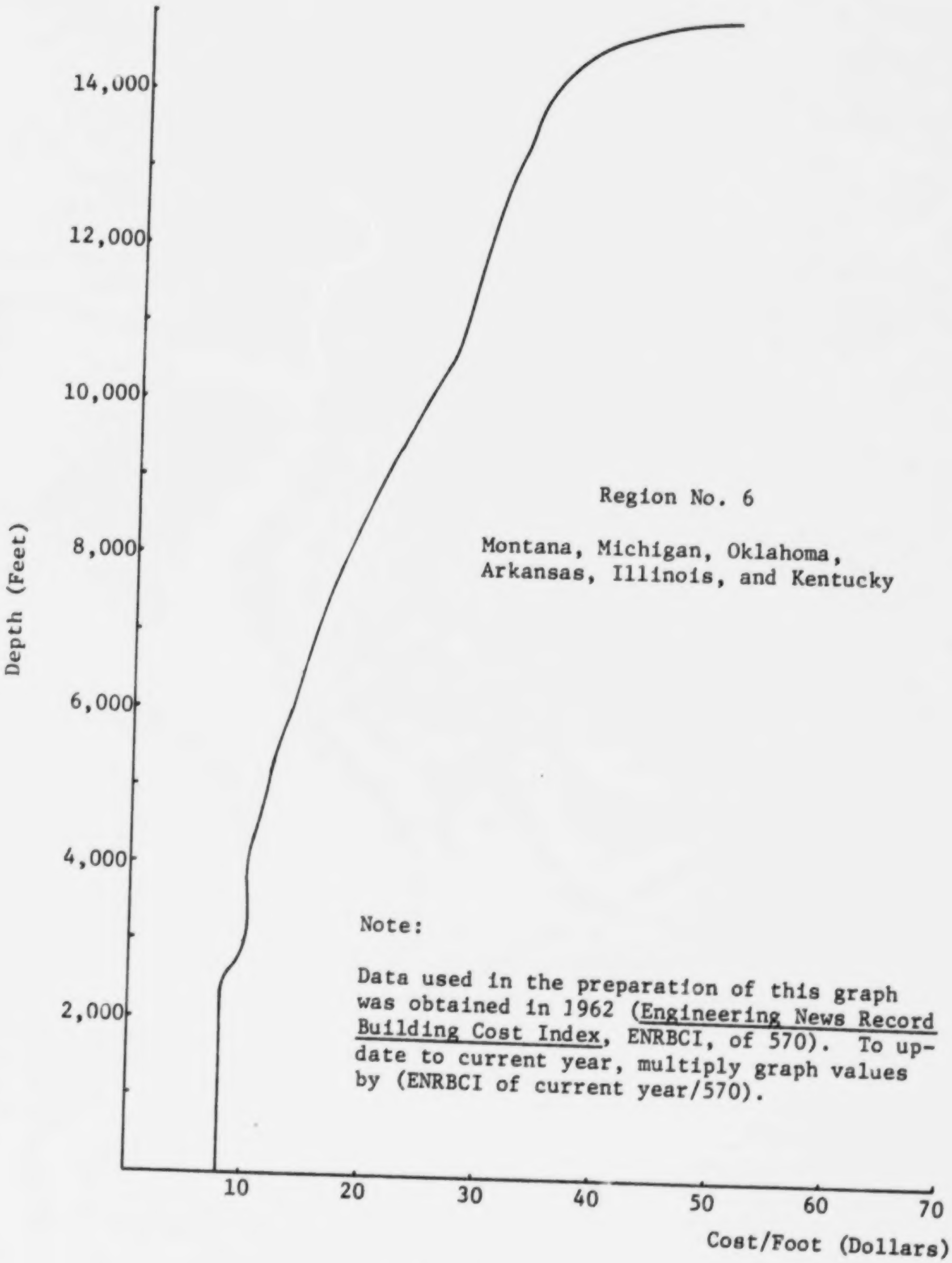
Depth vs Cost/Foot

Figure 26. Region Rating Code 4.[68]



Depth vs Cost/Foot

Figure 27. Region Rating Code 5.[68]



Region No. 6

Montana, Michigan, Oklahoma, Arkansas, Illinois, and Kentucky

Note:

Data used in the preparation of this graph was obtained in 1962 (Engineering News Record Building Cost Index, ENRBCI, of 570). To update to current year, multiply graph values by (ENRBCI of current year/570).

Depth vs Cost/Foot

Figure 28. Region Rating Code 6.[68]

The value thus obtained is the well drilling cost adjusted for diameter and expressed in thousands of dollars (K dollars).

The following is a computer printout of the main program for brine disposal.

```
FORTRAN IV G LEVEL  20                 MAIN              DATE = 71356        12/55/56             PAGE 0001

               C      MAIN PROGRAM FOR BRINE DISPOSAL
               C   1=INJECTION    2=EVAPORATION    3=CONVEYANCE
 0001                 COMMON / C / ENG, CRF, XC, XE
 0002                 COMMON/ TABLE/ TT1(10,2), TT2(11,2),TT3A(15,2), TT3B(13,2),        1060
                    1     TT3C(13,2), TT3D(14,2), TT3E(11,2), TT3F(15,2), TT4(4,2),      070
                    2     TT5J(20,2), TT5K(23,2), TT6(7,2), TT7(13,2), TT8(6,2),         080
                    3     TT9(18,2), TT10(12,2), TT11(8,2)                               090
 0003                 READ 10,C1,C2,C3                                                   110
 0004            10   FORMAT(3F10.0)
 0005                 IF(C1.EQ.1.) GO TO 21
 0006                 GO TO 25
 0007            21   CALL INJECT
 0008            25   IF(C2.EQ.2.) GO TO 31
 0009                 GO TO 33
 0010            31   CALL EVAP
 0011            33   IF(C3.EQ.3.) GO TO 41
 0012                 GO TO 50
 0013            41   CALL CONVEY
 0014            50   STOP
 0015                 END
```

```
                 1IT, L, H, PHI, RW,RR, E, CCRI, VCPIPE, VCFORM, SPGR, ECHIF,      3011
                 2XP,CPP,FL,XLAST
            C     FORMAT FOR READ                                                  3025
0048          130 FORMAT (I3, 10A1, A2, F5.0, F3.3, F4.0, I2,F4.3,F3.0, I1, F5.0,   3030
                 1F3.0, F2.2, F4.3, F4.0, F3.2, F4.1,F3.2, F3.2, F2.1, F3.2/
                 2F5.0,2F4.0,F10.0)
            C     CONVERT INPUTS TO PROPER MAGNITUDE                               3040
0049              XC = XC * 1000.                                                  3041
0050              XF=XF*1000.
0051              CCRI = CCRI * 1000.
0052              FL = 25.
            C     SET UP DUMMY FORMATION NAME
0053              DATA FNAME/6H TEST /
            C     SET INITIAL N EQUAL TO 1
0054              N = 1
            C     CALCULATE WELLHEAD EQUIPMENT COST
0055              IF (D  .GT. 4.0) GO TO 201
0056          200 WHC = 1050.
0057              GO TO 210
0058          201 IF (D .GT. 6.0) GO TO 203
0059          202 WHC = 1050. + 30. * (D - 4.0)
0060              GO TO 210
0061          203 WHC = 1110. + 101.6 * (D-6.0)
0062          210 CONTINUE
            C     CALCULATE PLASTIC LINING COSTS
0063              RAPL = .1572 * D
            C     CALCULATE PRODUCTION HOLE DIAMETER                               30
0064              RW = 7.0 + 1.5 * (D-1.0)
            C     CONVERT INTEREST RATE FROM PERCENT                               3075
0065            2 II = II * .01                                                    3080
            C     CALCULATE CAPITAL RECOVERY FACTOR                                3085
0066              CRF = (II*(1. + II)**Y)/((1. + II)**Y - 1.)                      3090
            C     CALCULATE DENSITY                                                3095
0067              RHO = 62.43 * SPGR                                               3100
            C     CONVERT RW FROM DIA TO RADIUS  AND INCHES TO FEET                3095
0068              RW = RW / 24.                                                    3110
            C     CALCULATE STATIC HEAD                                            3115
0069              PC = L * RHO / 144.                                              3120
            C     N = NUMBER OF WELLS IN THE INJECTION FIELD                       3070
0070              IF(N .EQ. 0) GO TO 3
0071              GO TO 33
            C     FIND NUMBER OF WELLS                                             3100
0072            3 N = N + 1                                                        3130
            C     CALCULATE FLOW RATE DOWN EACH WELL                               3135
0073           33 XI = XC/N                                                        3140
            C     CALCULATE FLUID VELOCITY IN INJECTION CONDUIT                    3145
0074              V = .000284 * XI / (D**2)                                        3150
            C     CALCULATE REYNOLDS NUMBER                                        3155
0075              XNRE = ( 124. * RHO * D * V ) / VCPIPE                           3160
            C     LOOK-UP FANNING FRICTION FACTOR                                  3165
0076              CALL TLU(TTT1, 1, 10, XNRE, F, 1, 1)                             3170
            C     CALCULATE FRICTION LOSS                                          3209
0077              PF = ( RHO / 193.02 ) * F * L * ( V**2 ) / D                     3210
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FORTRAN IV G LEVEL  20                 INJECT              DATE = 71356          12/59/56                 PAGE 0001

0001               SUBROUTINE INJECT
0002               DOUBLE PRECISION SABOV,SBELO,FNAME,TEMP
0003               REAL K,II,L,KW,KW2,LOGF
0004               INTEGER Y
0005               COMMON / C / ENR, CRF, XC, XP                                       1060
0006               COMMON/ TABLE/ TT1(10,2), TT2(11,2),TT3A(19,2), TT3B(13,2),         070
                  1    TT3C(13,2), TT3D(14,2), TT3E(11,2), TT3F(15,2), TT4(4,2),       080
                  2    TT5J(20,2), TT5N(23,2), TT6(7,2), TT7(13,2), TT8(6,2),          090
                  3    TT9(18,2), TT10(12,2), TT11(8,2)                                110
0007               DIMENSION PLACE(40), WORK(40), FNAME(6), TEST(20)                   1110
0008               DATA BLANK/' '/,SABOV/'ABOVE BR'/,SBELO/'BELOW BR'/
0009               DATA TEST/' 1','1 ',' 2','2 ',' 3','3 ',' 4','4 ',' 5','5 ',' 6',
                  1'6 '/
0010               LOGF(X)=ALOG(X)
0011               SQRTF(X)=SQRT(X)
0012               ABSF(X)=ABS(X)
            C      PRINT PERMANENT DATA TABLES                                          2005
0013               PRINT 301, (TT1(I,1), TT1(I,2), I=1,10)                              2010
0014               PRINT 302, (TT2(I,1), TT2(I,2), I=1,11)                              2020
0015               PRINT 303, (TT3A(I,1), TT3A(I,2),I=1,19)                             2030
0016               PRINT 304, (TT3B(I,1), TT3B(I,2), I=1,13)                            2040
0017               PRINT 306, (TT3C(I,1), TT3C(I,2), I=1,13)                            2050
0018               PRINT 307, (TT3D(I,1), TT3D(I,2), I=1,14)                            2060
0019               PRINT 308, (TT3E(I,1), TT3E(I,2), I=1,11)                            2070
0020               PRINT 309, (TT3F(I,1), TT3F(I,2), I=1,15)                            2080
0021               PRINT 310, (TT4(I,1), TT4(I,2), I=1,4)                               2090
0022               PRINT 311, (TT5J(I,1), TT5J(I,2), I=1,20)                            2100
0023               PRINT 305, (TT5N(I,1), TT5N(I,2), I=1,23)                            2110
0024               PRINT 312, (TT6(I,1), TT6(I,2), I=1,7)                               2120
0025               PRINT 313, (TT7(I,1), TT7(I,2), I=1,13)                              2130
0026               PRINT 314, (TT8(I,1), TT8(I,2), I=1,6)                               2140
0027               PRINT 315, (TT9(I,1), TT9(I,2), I=1,18)                              2150
0028               PRINT 316, (TT10(I,1), TT10(I,2), I=1,12)                            2160
0029               PRINT 317, (TT11(I,1), TT11(I,2), I=1,8)                             2162
0030           301 FORMAT (1H1, 3HTT1,//(2F20.4))                                       2210
0031           302 FORMAT (1H1, 3HTT2,//(2F20.4))                                       2220
0032           303 FORMAT (1H1, 4HTT3A,// (2F20.4))                                     2230
0033           304 FORMAT (1H1, 4HTT3B, // (2F20.4))                                    2240
0034           306 FORMAT (1H1, 4HTT3C,// (2F20.4))                                     2250
0035           307 FORMAT (1H1, 4HTT3D, // (2F20.4))                                    2260
0036           308 FORMAT (1H1, 4HTT3E, // (2F20.4))                                    2270
0037           309 FORMAT (1H1, 4HTT3F, // (2F20.4))                                    2280
0038           310 FORMAT (1H1, 4HTT4 , // (2F20.4))                                    2290
0039           311 FORMAT (1H1, 4HTT5J, // (2F20.4))                                    2300
0040           305 FORMAT (1H1, 4HTT5N, // (2F20.4))                                    2310
0041           312 FORMAT (1H1, 4HTT6 , // (2F20.4))                                    2320
0042           313 FORMAT (1H1, 4HTT7 , // (2F20.4))                                    2330
0043           314 FORMAT (1H1, 4HTT8 , // (2F20.4))                                    2340
0044           315 FORMAT (1H1, 4HTT9 , // (2F20.4))                                    2350
0045           316 FORMAT (1H1, 4HTT10, // (2F20.4))                                    2360
0046           317 FORMAT(1H1, 4HTT11, // (2F20.4))                                     2362
            C      READ DATA INPUT CARDS                                                3005
0047             1 READ 100, JC, (PLACE(I), I = 1,10), BRC, XC, RKW, CPA, Y, II, ENR,3010
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               C     CALCULATE DISTANCE TO OUTERMOST FLOOD FRONT                        3215
 0078                RF = 124.6  * SQRT(F(I) * V /(1000. * H * PHI))                    3220
               C     CALCULATE DRIVING PRESSURE WITH DARCY EQUATION                     3225
 0079                DELP =(VI * .474294482 * LOG(RF/RW))/(128.5*PK*H) * VCFDM          3230
               C     CALCULATE WELL SPACING                                             3235
 0080                RS = 2.*RF                                                         3240
               C     COMPUTE CASINGHEAD PRESSURE FROM OTHER PRESSURE TERMS              3245
 0081                PCH = DELP + PR - PC + PF                                          3250
               C     SET UP DUMMY VARIABLE FOR DISTANCE TO FLOODFRONTS                  3250
 0082                DDD = RF/2.                                                        3251
 0083                PRINT 1111, PR, PK, VI, N, V, XNRE, H, RF,DDD, DELP, PC, PCH       3252
 0084           1111 FORMAT(1H,/////,25H  PRESSURE TEST PRINT-OUT,/ , 6H P R =, F6.0,/ 3252
                   1  5H PK =, F7.3,/,5H VI =, F8.0,/, 4H N =, I5,/, 4H V =, F20.5,/, 3254
                   2  7H XNRE =, F20.5,/, 4H H = , F20.5,/, 5H RF =, F20.5,/          3255
                   3 22H RF(BEFORE DOUBLING) =,  F6.0,/, 7H DELP =, F20.5,/ , 6H PC  =3256
                   4   ,F20.5,//,6H PCH =, F20.5)                                     3257
               C     TEST  N                                                            3256
 0085                IF(N .GT. 25) GO TO 77
 0086                GO TO 76
 0087             77 SWN = 1                                                            3258
 0088                GO TO 93                                                           3259
 0089             76 SWN = 0                                                            3260
               C     TEST COMPUTED PCH AGAINST MAX. ALLOWABLE PCH                       3260
 0090                IF(PCH  - PCHTF * L ) 93, 4, 4                                     3260
 0091             93 IF(PCH-0.0)92, 91, 91                                              3262
 0092             92 LUP= 1                                                             3264
 0093                PCH= 0.0                                                           3266
 0094                GO TO 4                                                            3267
 0095             91 LUP = 0                                                            3268
               C     N IS NOW THE MAXIMUM NUMBER OF WELLS NEEDED                         3270
               C     RS IS THE MINIMUM DISTANCE BETWEEN ANY 2 WELLS                     3280
 0096              4 CONTINUE                                                           3290
               C     USE SUBR X  WFD TO DESIGN WELLFIELD                                3295
 0097                CALL WFD(N,XC,RS,PCH,SEAF,COLC,COPS,CAWDS,XLL, PHC )               3300
               C     CALCULATE FRICTION LOSSES IN DISTRIBUTION SYSTEM PIPING            3305
 0098                FL = .0013 * XLL                                                   3310
               C     COMPUTE TOTAL INJECTION PUMP HEAD                                  3215
 0099                FI = PCH + FL                                                      3320
 0100                IF(LUP -1) 86, 85, 85                                              3322
 0101             85 BHP = 1.1                                                          3324
 0102                GO TO 88                                                           3326
               C     CALCULATE REQD BRAKE HORSEPOWER FOR INJECTION PUMPS                3329
 0103             86 BHP = (XC * FI/2468000.)/.65                                       3330
               C     COMPUTE ENERGY REQUIREMENTS FOR INJECTION PUMPS                    3335
 0104             88 KW = BHP * .746 / .93                                              3340
               C     CONVERT  HP  TO FEET OF HEAD                                       3345
 0105                FI = FI / ( RHO / 144. )                                           3350
               C     CONVERT FLOW RATE FROM GPD TO GPM                                  3355
 0106                GPM = XC/1440.                                                     3360
               C     CALCULATE DIAMETER OF SUPPLY LINE                                  3365
 0107                DPD = .00581 * ( XC**.45 ) * ( RHO**.14 )                          3370
               C     COMPUTE HEAD LOSS IN SUPPLY LINE                                   4005
 0108                HF = .003 * DPM * 5280.                                            4010
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              C      DETERMINE TOTAL HEAD REQUIRED
 0109                DELH = EL - HF                                                  4019
              C      CALCULATE SUPPLY HEAD REQD                                      4020
 0110                PMIN = ABSF ( DELH ) * RHO / 144.                               4025
              C      SET BHP  AND  KW  EQUAL TO ZERO                                 4030
 0111                BHP2=0.                                                         4034
 0112                KW2=0.
 0113                IF(DELH - 0.) 5, 6, 6
              C      COMPUTE BHP NEEDED FOR SUPPLY PUMPS                             4040
 0114              5 BHP2 = EXC * PMIN/2468000.)/.85                                 4045
              C      COMPUTE POWER REQUIREMENTS                                      4050
 0115                KW2 = BHP2 * .746 / .93                                         4055
              C      CALCULATE CAPACITY OF STORAGE FACALITIES                        4060
 0116              6 SCXC = XC/ 3.                                                   4139
 0117                IF(N - 1) 86, 87, 86                                            4140
 0118             87 RF = 0.0                                                        4210
 0119             86 TEMP = SPFLC                                                    4220
 0120                IF(FL - 0.) 85, 84, 84                                          4230
 0121             85 TEMP = SAPCV                                                    4240
              C      CENTER TITLE ON OUTPUT PAGE                                     4250
 0122             84 KL = 0                                                          4255
 0123                DO 83 IL=1,35                                                   4260
 0124             83 WORK(IL) = BLANK                                                4270
 0125                DO 81 IL = 1, 35                                                4280
 0126                JL = 40 - IL                                                    4290
 0127                IF(PLACE(JL) .EQ. BLANK) GO TO 82                               4300
 0128                GO TO 80
 0129             82 KL = KL + 1
 0130             81 CONTINUE                                                        4320
 0131                GO TO 78                                                        4330
 0132             80 KL = KL/2                                                       4340
 0133                DO 79 ILL = 1, JL                                               4350
 0134             79 WORK(KL + ILL) = PLACE(ILL)                                     4360
              C      PRINT 2ND PAGE TITLES                                           4370
 0135             78 PRINT 103, (WORK(I), I=1,10),                                   4404
                    1                                                                4405
                             RRC, N, RF, XC, IFC, PCH, XP, FI, IPC, CPM, AHP, Y, KW 4410
 0136                F=0.
 0137                CPM1=0.
 0138                FFL = ABSF(FL)
 0139                IF(DELH) 10, 11, 11                                             4413
 0140             10 F=(-1.)*DELH                                                    4415
 0141                CPM1=CPM
              C      PRINT 2ND PAGEDATA                                              4415
              C      SET UP TEMP PRINTING VARIABLES                                  4419
 0142             11 PRINT 103, II, RKW, F, CFA,CPM1, ENR, XC, SCXC, CPM, TEMP, FFL,  4420
                    1     (FNAME(I), I=1,6)                                          4430
 0143                IF(L - 0) 13, 12, 13                                            4440
 0144             12 PRINT 104                                                       4450
 0145                GO TO 14                                                        4460
 0146             13 PRINT 105                                                       4470
 0147             14 PHID = PW * 24.                                                 4480
 0148                PRINT 106, L, PHI, PW, H, PR, P, PHIC, SPCR, VCPIPE, VCFCPM, PCHTF4490
              C                                                                      5070
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                C        BEGIN COST COMPUTATIONS                                                    5080
                C                                                                                   5090
                C        SELECT PROPER  RRC  DISTRICT                                               5095
 0149              14  DO 15 I=1,12
 0150                  IF(IRRC .EQ. IRSTCT(I)) GO TO 16
 0151               15 CONTINUE                                                                     5120
 0152                  PRINT 131, RRC                                                               5130
 0153                  GO TO 99                                                                     5150
                C         RRC = --1--  --2--  --3--  --4--  --5--  --6--
 0154               16 GO TO (21,21, 22,22, 18,18, 19,19, 20,20, 17,17),I
                C        LOOK-UP DRILLING COST                                                      5165
 0155               17 CALL TBKL(TT2A, 2, 15, L, F, C, C)                                           5170
 0156                  GO TO 23                                                                     5210
 0157               18 CALL TBKL(TT2B, 2, 13, L, F, C, C)                                           5220
 0158                  GO TO 23                                                                     5230
 0159               19 CALL TBKL(TT2C, 2, 13, L, F, C, C)                                           5240
 0160                  GO TO 23                                                                     5250
 0161               20 CALL TBKL(TT2D, 2, 14, L, F, C, C)                                           5260
 0162                  GO TO 23                                                                     5270
 0163               21 CALL TBKL(TT2E, 2, 11, L, F, C, C)                                           5280
 0164                  GO TO 23                                                                     5290
 0165               22 CALL TBKL(TT2F, 2, 15, L, F, C, C)                                           5300
 0166               23 F = L * F                                                                    5310
                C        COMPUTE PLASTIC LINING COST                                                5311
 0167                  IF(LI)800,801,800
 0168              800 PLC = RAPL * (L-LI*H)
 0169                  GO TO 802
 0170              801 PLC = RAPL * (L-LI*H) +10. * H
 0171              802 CONTINUE
                C        LI IS 0 FOR A SANDSTONE FORMATION, THEREFORE H IS NOT USED IN        5330
 0172                  CALL TBKL(TT4, 4, 4, L, FF, C, C)                                            5350
                C        CALCULATE COST OF EACH WELL                                                5355
 0173                  TWC = F + WHC + PLC + FF + CCP1                                              5360
 0174             1001 CONTINUE
                C        COMPUTE COST OF ALL WELLS                                                  5365
 0175                  TWC = N * TWC                                                                5370
 0176                  CALL TBKL(TT11, 11, 5, DDD, F, C, C)                                         6030
                C        COMPUTE SUPPLY LINE CONST COST                                             6045
 0177               26 CCSS = .6 * DEM * 5280.                                                      6050
                C        CALCULATE SUPPLY LINE R-O-W COST                                           6059
 0178                  C2WSS = .375 * DEM * 5280.                                                   6060
                C        CALCULATE COST OF SUPPLY PIPE                                              6075
 0179                  SSAP = F * DEM * 5280.                                                       6080
                C        NO LINING REQD FOR SUPPLY PIPE                                             6085
 0180                  CSLC = 0.0                                                                   6090
                C        LOOK-UP PUMP H. P. SIZES                                                   6095
 0181                  CALL TBKL(TT7, 7, 13, PHP, F, 1, 1)                                          6100
 0182                  CPUMP = PHP * F                                                              6110
 0183                  CPUMP2 = 0.0                                                                 6115
 0184                  IF(PFLW)  27, 28, 28                                                         6120
 0185               27 CALL TBKL(TT7, 7, 13, PHP2, F, 1, 1)                                         6130
 0186                  CPUMP2 = PHP2 * F                                                            6140
                C        SET UP TEMP VARIABLE FOR STORAGE CAPACITY                                  6149
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 0187             20 F = XC/2.                                                             6150
               C     LOOK-UP STORAGE COSTS                                                 6159
 0188                CALL TLKUP(TTR, R, 6, F, STRC, 0, 0)                                  6160
               C     CALCULATE TREATMENT PLANT CAPITAL COSTS                               6165
 0189                TPLC = 10.**(4.062 + .0486 * LOG10(XC))                               6170
               C     LOOK-UP WELL FIELD  C+P                                               6205
 0190                CALL TLKUP(TTS, S, 18, XC, F, 0, 0)                                   6210
               C     SET UP FAR CONVERSION FACTOR                                          6241
 0191                CFNR = ENR/570.                                                       6215
               C     ROUND OFF ALL $-ITEMS TO NEAREST DOLLAR                               6219
 0192                AX=TWC*CFNR+.5
 0193                TWC=AX
 0194                AX=SSAC*CFNR+.5
 0195                SSAC=AX
 0196                AX=CSLC*CFNR+.5
 0197                CSLC=AX
 0198                AX=SDAC*CFNR+.5
 0199                SDAC=AX
 0200                AX=CDLC*CFNR+.5
 0201                CDLC=AX
 0202                AX=TPLC*CFNR+.5
 0203                TPLC=AX
 0204                AX=CPUMP*CFNR+.5
 0205                CPUMP=AX
 0206                AX=CPUMP2*CFNR+.5
 0207                CPUMP2=AX
 0208                AX=STRC*ENR/580.+.5
 0209                STRC=AX
 0210                AX=.25*A*CPA+.5
 0211                WFSC=AX
 0212                AX=5.*CPA+.5
 0213                RSSC=AX
 0214                SLTLC=SSAC+CSLC
 0215                DSTLC=SDAC+CDLC
 0216                SLCRC=CCSS+CRWSS
 0217                DSCRC=CCDS+CRWDS
 0218                AX=F+.5
 0219                WFCM=AX
 0220                AX=.002555*XC+.5
 0221                WFSM=AX
 0222                WFWCW=A*L
 0223                AX=.15*F+.5
 0224                WFPC=AX
 0225                AX=.345*F+.5
 0226                WFGA=AX
 0227                RSCM=WFCM
 0228                AX=.15*F+.5
 0229                RSPC=AX
 0230                AX=.345*F+.5
 0231                RSGA=AX
 0232                AX=8760.*PKW*KW2+.5
 0233                SLPC=AX
 0234                AX=8760.*RKW*KW+.5
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0235                 PSPC=KX
0236                 F = F * 1.495
               C     CALCULATE AND PRINT REMAINDER OF COST ITEMS                         6340
               C     COST WELLHEAD COMPONENTS                                            6339
0237                 CALL MONEY(TWC, WFSC, WFSM + WFMCV + F, C., WC, WE, WICM,           6345
                    1          WSLM, WEAM, WEINC, WSLMAF, WFC, WFC)                      6350
               C     COST SUPPLY LINE COMPONENTS                                         6360
0238                 CALL MONEY(SLTLC + CPUMP2, SLCRC, SLFC, .0025, SC, SF, SICM,        6365
                    1          SSLM, SLAM, SLINC, SSLMAF, SFC, SFC)                      6370
               C     COMPUTE SUPPLY LINE  C+M                                            6380
0239                 KX=.0025*SSLM+.5                                                    6385
0240                 SLOM=KX
               C     COST DISTRIBUTION SYSTEM COMPONENTS
0241                 CALL MONEY(DSTLC, DSCRC, 0., .0025, DC, DF, DICM,                   6405
                    1          DSLM, DSAM, DSINC, DSLMAF, DFC, DFC)                      6410
               C     COMPUTE DISTRIBUTION SYSTEM  C+M                                    6420
0242                 KX=.0025*DSLM+.5                                                    6425
0243                 DSOM=KX
               C     LOOK-UP TREATMENT PLANT  C+M
0244                 CALL TLKUP(TTIC, TC, 12, XC, TECM, 1, 1)                            6435
               C     ROUND OFF TREATMENT PLANT  C+M                                      6440
0245                 KX=TECM+.5                                                          6444
0246                 TPOM=KX
               C     COST TREATMENT PLANTPLANT
0247                 CALL MONEY(TPLC, 0., TECM, 0.,  TC, TPE, TPICM,                     6449
                    1          TSLM, TPAM, TPINC, TSLMAF, TEC, TFC)                      6450
               C     COST PUMPING INSTALLATIONS                                          6460
0248                 CALL MONEY(CPUMP, STRC + PSSC, PSPC + F, .0025, PC, PF, PICM,       6465
                    1          PSLM, PSAM, PSINC, PSLMAF, PFC, PFC)                      6470
               C     COMPUTE PUMP STATION  C+M                                           6480
0249                 KX=.0025*PSLM+.5                                                    6485
0250                 PSSM=KX
               C     CALCULATE TOTAL CAPITAL COSTS
0251                 T=1.                                                                6495
0252                 TS1 = WSLM + SSLM + DSLM + TSLM + PSLM
               C     REDEFINE CAP COST IN MILLIONS                                       6510
0253                 XTCC = ( WSLM + SSLM + DSLM + TSLM + PSLM ) / 1000000.              6511
0254                 PRINT 107, (PLACE(I), I=1,10), (PNAME(J), J=1,6), XD, IEC, XP,      6512
                    1          IEC, A                                                    6520
0255                 PRINT 108, WSLM, SSLM, DSLM, TSLM, PSLM, TS1                        6530
0256                 PRINT 109, TWC, T, T, T, T, TWC                                     6540
0257                 TS1 = WFSC + PSSC                                                   6550
0258                 PRINT 110, WFSC, T, T, T, PSSC, TS1                                 6560
0259                 TS1 = SLTLC + DSTLC                                                 6570
0260                 PRINT 111, T, SLTLC, DSTLC, T, T, TS1                               6610
0261                 TS1 = SLCRC + DSCRC                                                 6620
0262                 PRINT 112, T, SLCRC, DSCRC, T, T, TS1                               6630
0263                 PRINT 113, T, T, T, TPLC, T, TPLC                                   6640
0264                 TS1 = CPUMP2 + CPUMP                                                6650
0265                 PRINT 114, T, CPUMP2, T, T, CPUMP, TS1                              6660
0266                 PRINT 115, T, T, T, T, STRC, STRC                                   6670
0267                 TS1 = WC + SC + DC +  TC + PC                                       6680
0268                 PRINT 116, WC, SC, DC,  TC, PC, TS1                                 6690
                                                                                         6700
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0269              TS1 = WF + SF + DF + TFF + PF                                      6710
0270              PRINT 117, WF, SF, DF, TFF, PF, TS1                                6720
0271              TS1 = WICM + SICM + DICM + TPICM + PICM                            6730
0272              PRINT 118, WICM, SICM, DICM,TPICM, PICM, TS1                       6740
0273              TS1 = WSUMAF + SSUMAF + DSUMAF + TSUMAF + PSUMAF                   6750
0274              PRINT 119, WSUMAF,  SSUMAF, DSUMAF, TSUMAF, PSUMAF, TS1            6760
0275              TS1 = WFCM + SLCM + DSCM + TPCM + PSCM                             6770
0276              PRINT 120, WFCM, SLCM, DSCM, TPCM, PSCM, TS1                       8810
0277              TS1 = WFSM + PSSM                                                  8820
0278              PRINT 121, WFSM, T, T, T, PSSM, TS1                                8830
0279              PRINT 122, WFWCV, T, T, T, T, WFWCV                                8840
0280              TS1 = WFPC + PSPC                                                  8844
0281              PRINT 123, WFPC, T, T, T, PSPC, TS1                                8846
0282              TS1 = WFCA + PSCA                                                  8850
0283              PRINT 124, WFCA, T, T, T, PSCA, TS1                                8860
0284              TS1 = WFAM + SLAM + DSAM + TPAM + PSAM                             8870
0285              PRINT 125, WFAM, SLAM, DSAM, TPAM, PSAM, TS1                       8880
0286              TS1 = WFINC + SLINC + DSINC + TPINC + PSINC                        8890
0287              PRINT 126, WFINC, SLINC, DSINC, TPINC, PSINC, TS1                  8900
0288              TS1 = SLPC + PSPC                                                  8910
0289              PRINT 127, T, SLPC, T, T, PSPC, TS1                                8920
0290              TCE = WEC + SEC + TEC + PEC                                        8930
0291              PRINT 128, WEC, SEC, DEC, TEC, PEC, TCE                            8940
0292              TS1 = WPC + SPC + DPC + TPC + PPC                                  8950
0293              PRINT 129, WPC, SPC, DPC, TPC, PPC, TS1                            8960
            C     REDEFINE XO IN MILLIONS                                            8964
0294              XOO = XO / 1000000.                                                8966
0295           77 SWN = 0                                                            8967
0296              IF(XLAST.EQ.1.) GO TO 587
0297              GO TO 1
            C    [illegible] STOP
0298           55 CONTINUE
            C                                                                        7600
            C                                                                        7520
            C     OUTPUT FORMATS                                                     7510
            C                                                                        7090
            C                                                                        7100
0299          743 FORMAT(I4,I3,10A1,  F8.0,F5.0, 2PF3.0, 3PF4.0, 0PF4.0, I2, 4PF8.07104
             1    , 2X)                                                              7105
            C                                                                        7720
            C                                                                        7755
0300          102 FORMAT(1H1,40X,10A1,//,25X,5HINPUT,53X,6HOUTPUT,///,2X,14HR R C DI7110
               1STRICT,29X,A2,23X,15HNUMBER OF WELLS,25X,I3,//,67X, 7HSPACING,28X,7120
               2F8.0,5H FEET,/,17H  EFFLUENT VOLUME,22X,F8.0,4H CPD,//,24H  EFFLUENT7130
               2NT CONCENTRATION,
               3                16X,I7,4H PPM,16X,20HTUBING HEAD PRESSURE,15X,F8.0,7140
               44H PSI,//,22H  PRODUCT PETRO VOLUME,17X,F8.0,4H CPD,16X,19HINJECTI7150
               5ON PUMP HEAD,16X,F8.0,5H FEET,//,29H  PRODUCT PETRO CONCENTRATION,7160
               612X,I6,4H PPM,16X,23HINJECTION PUMP CAPACITY,12X,F8.0,4H GPM,//,  7170
               767X,25HINJECTION PUMP BRAKE HORSE POWER   ,F8.0,4H BHP,/,14H  PROJ7180
               8ECT LIFE,31X, I2 ,6H YEARS,/,67X,20HINJECTION PUMP MOTOR,15X,F8.0,7190
               93H KW)                                                               7200
0301          103 FORMAT(23H  CAPITAL DISCOUNTED AT,20X,2PF4.2, 5H PERCENT ,//,      7210
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                1 12H  POWER RATE,                                               7215
                2   25X,OPF6.4,6H $/KWH,14X,16HSUPPLY PUMP HEAD,15X,F8.0,5H FEET,//7220
                311H  LAND COST,32X,F4.0,7H $/ACRE,13X,20HSUPPLY PUMP CAPACITY,15X,7230
                3 F8.0,                                                          7235
                44H GPM,//,25H  PAR BUILDING COST INDEX,18X,F4.0,/,67X,24HTREATMENT7240
                5 PLANT CAPACITY,11X,F8.0,4H GPD,//,13H  WELL FIELD ,54X,16HSTORAGE7250
                6 CAPACITY,15X,F8.0,5H GAL.,//,6X,26HDISTANCE FROM PR.COL POINT,12X7260
                7,F3.0,6H MILES,//,6X,30HELEVATION OF INJECTION STATION,/,11X,AF,  7270
                8ICH.COL POINT,13X,F5.0,5H FEET,///,16H  FORMATION NAME,32X,5A8,A2)7280
0202        104 FORMAT(1H0,10H LITHOLOGY,33X, 5HSANDSTONE)                       P010
0203        105 FORMAT(1H0,10H LITHOLOGY)                                        P020
0204        106 FORMAT(1H0,12H TOTAL DEPTH,28X,F6.0,5H FEET,//,10H  POROSITY,34X, P030
                1 30F3.0,9H PERCENT ,                                            P035
                2  //,14H  PERMEABILITY,28X,OPF5.3,8H DARCIES,//,18H  EFFECTIVE HEIP040
                3GHT,25X,F4.0,5H FEET,//,20H  RESERVOIR PRESSURE,22X,F5.0,4H PSI,//P050
                4/,14H  TUBING I. D.,27X,F6.3,7H INCHES,//,23H  PRODUCTION HOLE I. P060
                5D.,16X,F6.3,7H INCHES,//,18H  SPECIFIC GRAVITY,24X,F5.3,//,     P070
                6 25H  EFFLUENT VISCOSITY IN--,/, 21H     INJECTION TUBING,20X,  P080
                7 F6.3, 3H CP,/, 14H     FORMATION, 27X, F6.3, 3H CP,//,         P083
                8 30H  MAXIMUM PRESSURE TEST FACTOR, 12X, F5.3, 7H PSI/FT )      P087
0205        107 FORMAT(1H1,6X,9HLOCATION ,10A1,33X,9HR.R.CODE ,5A8,A2,/,7X,17H EFFP090
                1LUENT VOLUME ,F8.0,4H GPD,24X,27HEFFLUENT CONCENTRATION     ,I7, P100
                2 4H PPM,/,7X,16HPRODUCT VOLUME  ,F8.0,4H GPD,24X,28HPRODUCT EFFLU P110
                3CONCENTRATION ,I6,4H PPM,/,33X,17HNUMBER OF WELLS  ,I3,//,28X,4HWEP120
                4LL,8X,48HSUPPLY    DISTRIBUTION  TREATMENT   PUMP STATION,/,28X,5HP130
                5FIELD,8X,4HLINE,8X,44HSYSTEM        PLANT      AND  STORAGE   TOTALP140
                6)                                                               P150
0206        108 FORMAT(1H0,23HCAPITAL COST, $        ,6(F11.0,2X))                 P160
0207        109 FORMAT(1H0,22H  WELL COST            ,6(F11.0,2X), 9H  DOLLARS)    P170
0208        110 FORMAT(1H0,22H  SITE COST            ,6(F11.0,2X), 9H  DOLLARS)    P210
0209        111 FORMAT(1H0,22H  PIPE AND CEMENT       ,/,                          P220
                1         1H ,22H  LINING COST          ,6(F11.0,2X), 9H  DOLLARS)  P230
0210        112 FORMAT(1H0,22H  CONSTRUCTION AND      ,/,                          P240
                1         1H ,22H  RIGHT-OF-WAY COST     ,6(F11.0,2X), 9H  DOLLARS) P250
0211        113 FORMAT(1H0,22H  PLANT COST           ,6(F11.0,2X), 9H  DOLLARS)    P260
0212        114 FORMAT(1H0,22H  PUMP STATION COST    ,6(F11.0,2X), 9H  DOLLARS)    P270
0213        115 FORMAT(1H0,22H  STORAGE COST         ,6(F11.0,2X), 9H  DOLLARS)    P280
0214        116 FORMAT(1H0,22H  CONTINGENCIES        ,6(F11.0,2X), 9H  DOLLARS)    P290
0215        117 FORMAT(1H0,22H  ENGINEERING          ,6(F11.0,2X), 9H  DOLLARS)    P295
0216        118 FORMAT(1H0,22H  INTEREST ON           ,/,                          P300
                1         1H ,22H  CONSTRUCTION MONEY   ,6(F11.0,2X), 9H  DOLLARS,/) P310
0217        119 FORMAT(23H0ANNUAL EXPENDITURE, $ ,6(F11.0,2X),14H  DOLLARS/YEAR)   P320
0218        120 FORMAT(23H0  O + M               ,6(F11.0,2X),14H  DOLLARS/YEAR)   P330
0219        121 FORMAT(23H0  SUPPLIES + MATERIAL ,6(F11.0,2X),14H  DOLLARS/YEAR)   P340
0220        122 FORMAT(23H0  WORKOVERS           ,6(F11.0,2X),14H  DOLLARS/YEAR)   P350
0221        123 FORMAT(23H0  PAYROLL OVERHEAD    ,6(F11.0,2X),14H  DOLLARS/YEAR)   P360
0222        124 FORMAT(23H0  G + A               ,6(F11.0,2X),14H  DOLLARS/YEAR)   P370
0223        125 FORMAT(23H0  AMORTIZATION        ,6(F11.0,2X),14H  DOLLARS/YEAR)   P410
0224        126 FORMAT(23H0  INTEREST ON          ,/,                             P420
                1         23H  WORKING CAPITAL     ,6(F11.0,2X),14H  DOLLARS/YEAR)  P430
0225        127 FORMAT(23H0  POWER COST          ,6(F11.0,2X),14H  DOLLARS/YEAR,/)P440
0226        128 FORMAT(23H0  ANNUAL COST PER 1000,/,23H    GAL. EFFLUENT, $    ,   P450
                1         6(F11.4,2X),15H  DOLLARS/1000 GAL.)                       P460
```

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 0327          120 FORMAT(23H0  ANNUAL COST PER 1000,/,23H   GAL. PRODUCT, $      ,   8470
                 1       6(F11.4,2X),15H  DOLLARS/1000 GAL.)                            8480
 0328          121 FORMAT(1H1,14H BRC DISTRICT,, A2,11H IS UNKNOWN)                     8500
 0329         997  RETURN
 0330              END
```

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FORTRAN IV G LEVEL  20                WFD               DATE = 71356        12/55/56             PAGE 0001
 0001             SUBROUTINE WFD (N, XC, RF, RCH, FC, PLC, CC, RWC, XLL, RHO )       1010
          C       THIS SUBR DESIGNS THE DISTRIBUTION SYSTEM FOR THE WELLFIELD        1020
 0002             IF (N-1) 1, 1, 50                                                 1030
 0003          1  RF=0.
 0004             PLC=0.
 0005             CC=0.
 0006             RWC=0.
 0007             XLL=0.
 0008             RETURN
 0009         50  DD1= .00551 * ( XC / N )**.45 * RHO**.14 + .5                      1050
 0010             IF (N-5) 51, 51, 52                                               1060
 0011         51  CALL GETCST (DD1, RCH, CPP1,CLPP1,KSW)                             1070
 0012             C2=0.                                                             1080
 0013             C3=0.
 0014             C4 =0.
 0015             C5=0.
 0016             C6=0.
 0017             IF (N-3) 2, 3, 511
 0018          3  CC= 0.58                                                          1100
 0019             C1= 1.73                                                          1110
 0020             GO TO 99                                                          1120
 0021          2  CC= 0.5                                                           1130
 0022             C1= 1.0                                                           1140
 0023             GO TO 99                                                          1150
 0024        511  IF (N-5) 4, 5, 5                                                  1160
 0025          4  CC= 0.71                                                          1170
 0026             C1= 2.828                                                         1180
 0027             GO TO 99                                                          1190
 0028          5  CC= 1.0                                                           1200
 0029             C1= 4.0                                                           2010
 0030             GO TO 99                                                          2020
 0031         52  DD2= .00551 * ( 2. * XC / N )**.45 * RHO**.14 + .5                 2030
 0032             IF (N-5) 53, 53, 54                                               2040
 0033         53  CC= 2.0                                                           2050
 0034             C1= 4.0                                                           2060
 0035             C3=0.                                                             2070
 0036             C4=0.
 0037             C5=0.
 0038             C6=0.
 0039             CALL GETCST (DD2, RCH, CPP2, CLPP2, KSW)
 0040             CALL GETCS2 (DD1, KSW, CPP1, CLPP1)                               2090
 0041             IF (N-8) 531, 8, 9                                                2100
 0042          8  C2= 3.0                                                           2110
 0043             GO TO 99                                                          2120
 0044          9  C2= 4.0                                                           2130
 0045             GO TO 99                                                          2140
 0046        531  IF (N-6) 6, 6, 7                                                  2150
 0047          6  C2= 1.0                                                           2160
 0048             GO TO 99                                                          2170
 0049          7  C2=2.0                                                            2180
 0050             GO TO 99
 0051         54  DD3= .00551 * ( 3. * XC / N )**.45 * RHO**.14 + .5                 2200
 0052             IF (N-13) 55, 55, 56                                              3010
                                                                                    3020
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FORTRAN IV G LEVEL  20              DFC             DATE = 71356        12/59/56          PAGE 0002

 0053            55 C0= 2.0                                                        3030
 0054               C4=0.
 0055               C5=0.
 0056               C6=0.                                                          3050
 0057               CALL CFTCST (DD3, PCH, CPF3, CLPF3, KSW)                       3060
 0058               CALL CFTCS2 (DD2, KSW, CPF2, CLPF2)                            3070
 0059               CALL CFTCS2 (DD1, KSW, CPF1, CLPF1)                            3080
 0060               IF (N-12) 551, 12, 13                                          3090
 0061            12 C1= 7.0                                                        3100
 0062               C2= 1.0                                                        3110
 0063               C3= 3.0                                                        3120
 0064               GO TO 99                                                       3130
 0065            13 C1= 8.0                                                        3140
 0066               C2= 0.0                                                        3150
 0067               C3= 4.0                                                        3160
 0068               GO TO 99                                                       4010
 0069           551 IF (N-11) 10, 11, 11                                           4020
 0070            11 C1= 6.0                                                        4030
 0071               C2= 2.0                                                        4040
 0072               C3= 2.0                                                        4050
 0073               GO TO 99                                                       4060
 0074            10 C1= 5.0                                                        4070
 0075               C2= 3.0                                                        4080
 0076               C3= 1.0                                                        4090
 0077               GO TO 99                                                       4100
 0078            56 DD4= .0051 * ( 4. * DT / N )**.45 * RHO**.14 + .5              4110
 0079               C3= 3.0                                                        4120
 0080               IF (N-17) 57, 57, 58                                           4130
 0081            57 C1= 6.0
 0082               C5=0.
 0083               C6=0.                                                          4150
 0084               CALL CFTCST (DD4, PCH, CPF4, CLPF4, KSW)                       4160
 0085               CALL CFTCS2 (DD3, KSW, CPF3, CLPF3)                            4170
 0086               CALL CFTCS2 (DD2, KSW, CPF2, CLPF2)                            4180
 0087               CALL CFTCS2 (DD1, KSW, CPF1, CLPF1)                            5010
 0088               IF (N-16) 571, 16, 17                                          5020
 0089            16 C2= 3.0                                                        5030
 0090               C3= 1.0                                                        5040
 0091               C4= 3.0                                                        5050
 0092               GO TO 99                                                       5060
 0093            17 C2= 4.0                                                        5070
 0094               C3= 0.0                                                        5080
 0095               C4= 4.0                                                        5090
 0096               GO TO 99                                                       5100
 0097           571 IF (N-15) 14, 15, 15
 0098            15 C2=2.
 0099               C3=2.
 0100               C4=2.                                                          5120
 0101               GO TO 99
 0102            14 C2=1.
 0103               C4=1.                                                          5140
 0104               C3= 3.0                                                        5150
 0105               GO TO 99
```

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   50 DD5= .DD551 * ( 5. * XC / A )**.45 * RHO**.14 + .5       5160
      IF (N-21) 55, 55, 60                                      5170
   55 C1= 8.0                                                   6010
      C6= 0.0                                                   6020
      CALL CFTCS1 (DD5, DCH, CFF5, CLPF5, KSW)                  6030
      CALL CFTCS2 (DD4, KSW, CFF4, CLPF4)                       6040
      CALL CFTCS2 (DD3, KSW, CFF3, CLPF3)                       6050
      CALL CFTCS2 (DD2, KSW, CFF2, CLPF2)                       6060
      CALL CFTCS2 (DD1, KSW, CFF1, CLPF1)                       6070
      IF (N-20) 551, 20, 21                                     6080
   20 C2= 3.0                                                   6090
      C3= 0.0                                                   6100
      C4= 1.0                                                   6110
      C5= 3.0                                                   6120
      GO TO 99                                                  6130
   21 C2= 8.0                                                   6140
      C3=0.
      C4=0.
      C5= 4.0                                                   6160
      GO TO 99                                                  6170
  551 IF (N-18) 18, 18, 19                                      7010
   18 C2= 5.0                                                   7020
      C3= 0.0                                                   7030
      C4= 3.0                                                   7040
      C5= 1.0                                                   7050
      GO TO 99                                                  7060
   19 C2= 6.0                                                   7070
      C3= 0.0                                                   7080
      C4=2.
      C5=2.
      GO TO 99                                                  7100
   60 DD6= .DD551 * ( 6. * XC / A )**.45 * RHO**.14 + .5       7110
      CALL CFTCS1 (DD6, DCH, CFF6, CLPF6, KSW)                  7120
      CALL CFTCS2 (DD5, KSW, CFF5, CLPF5)                       7130
      CALL CFTCS2 (DD4, KSW, CFF4, CLPF4)                       7140
      CALL CFTCS2 (DD3, KSW, CFF3, CLPF3)                       7150
      CALL CFTCS2 (DD2, KSW, CFF2, CLPF2)                       7160
      CALL CFTCS2 (DD1, KSW, CFF1, CLPF1)                       7170
      IF(N-24) 601, 24, 25                                      8010
   24 C1= 11.0                                                  8020
      C2= 5.0                                                   8030
      C3= 3.0                                                   8040
      C4= 0.0                                                   8050
      C5= 1.0                                                   8060
      C6= 3.0                                                   8070
      GO TO 99                                                  8080
   25 C1= 12.0                                                  8090
      C2=4.
      C3=4.
      C6=4.
      C4=0.
      C5=0.
      IF (N-25) 99, 99, 26                                      8120
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FORTRAN IV G LEVEL  20                  DEC              DATE = 71356        12/55/56              PAGE 0004

 0159           26 PRINT 27, N                                                          8130
 0160              GO TO 99                                                             8140
 0161           27 FORMAT (1H1, 14HN IS EQUAL TO , I2)                                  8150
 0162          601 IF (N-23) 22, 23, 23                                                 8160
 0163           22 C1= 5.0                                                              9010
 0164              C2= 7.0                                                              9020
 0165              C3=1.
 0166              C6=1.
 0167              C4= 0.0                                                              9040
 0168              C5= 3.0                                                              9050
 0169              GO TO 99                                                             9060
 0170           23 C1= 10.0                                                             9070
 0171              C2= 6.0                                                              9080
 0172              C3=2.
 0173              C5=2.
 0174              C6=2.
 0175              C4= 0.0                                                              9100
 0176           99 PC=RF*(C1*CPF1 + C2*CPF2 + C3*CPF3 + C4*CPF4 + C5*CPF5 + C6*CPF6) 9110
 0177              PLC= RF* (C1*CLPF1 + C2*CLPF2 + C3*CLPF3 + C4*CLPF4 + C5*CLPF5 +  9120
                  1C6*CLPF6)                                                            9130
 0178              CC = 0.6*RF*(C1 + C2 + C3 + C4 + C5 + C6)                            9140
 0179              RWC= 0.075*RF* (C1  + C2 + C3 + C4 + C5 + C6)                        9150
 0180              XLI = CC*RF                                                          9160
 0181              RETURN                                                               9170
 0182              END
```

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FORTRAN IV G LEVEL  20                CETCS2            DATE = 71356        12/55/56            PAGE 0001

 0001                SUBROUTINE CETCS2 (CC, KSW, CPF, CLPF)                                1010
             C       THIS SUBR CALCULATES THE COST OF PIPE                                 1005
 0002                COMMON/ TABLE/ TT1(10,2), TT2(11,2),TT3A(19,2), TT3B(13,2),           070
                    1     TT3C(13,2), TT3D(14,2), TT3E(11,2), TT3F(15,2), TT4(4,2),        080
                    2     TT5J(20,2), TT5K(23,2), TT6(7,2), TT7(13,2), TT8(6,2),           090
                    3     TT9(18,2), TT10(12,2), TT11(6,2)                                 110
 0003                IF (KSW - 1) 20, 10, 10                                               1020
 0004             20 CALL TLKL(TT5J, 21, 20, CC, CPF, 0, 0)                                1030
 0005                GO TO 30                                                              1040
 0006             10 CALL TLKL(TT5K, 22, 23, CC, CPF, 0, 0)                                1050
 0007             30 CC = CC + 0.5                                                         1060
 0008                CALL TLKL(TT6, 6, 7, CC, CLPF, 0, 0)                                  1070
 0009                RETURN                                                                1080
 0010                END                                                                   1090
```

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FORTRAN IV G LEVEL  20              CFTCST           DATE = 71356        12/55/56             PAGE 0001

 0001             SUBROUTINE CFTCST (OD, PCH, CFF, CLPF, KSW)                            1010
            C     THIS SUBR COMPUTES THE REQD WEIGHT OF PIPE                             1021
 0002             COMMON/ TABLE/ TT1(10,2), TT2(11,2),TT3A(15,2), TT3B(13,2),             070
                 1    TT3C(13,2), TT3D(14,2), TT3E(11,2), TT3F(15,2), TT4(4,2),           080
                 2    TT5J(20,2), TT5A(23,2), TT6(7,2), TT7(13,2), TT8(6,2),              090
                 3    TT9(18,2), TT10(12,2), TT11(8,2)                                    110
 0003             CALL TLKL(TT2, 2,11, OD, VPRES, 0, 0)                                  1030
 0004             IF (VPRES-PCH) 10, 20, 20                                              1040
 0005          20 KSW= 0                                                                 1050
 0006             CALL TLKL(TT5J, 51, 20, OD, CPF, 0, 0)                                 1060
 0007             GO TO 30                                                               1070
 0008          10 KSW= 1                                                                 1080
 0009             CALL TLKL(TT5A, 52, 23, OD, CPF, 0, 0)                                 1090
 0010          30 OD = OD + 0.5                                                          1100
 0011             CALL TLKL(TT6, 6, 7, OD, CLPF, 0, 0)                                   1110
 0012             RETURN                                                                 1120
 0013             END                                                                    1130
```

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FORTRAN IV G LEVEL  20            TLKU              DATE = 71356        12/59/56              PAGE 0001

 0001              SUBROUTINE TLKU(TABLE,NC,K,VAT,CUT,LIN,LCUT)                          1010
          C        THIS SUBR PERFORMS THE TABLE LOOK-UPS-                                1025
 0002              DIMENSION TABLE(K,2)                                                  1020
 0003              VAR = VAT                                                             1021
 0004              IF(LIN) 10,11,10
 0005           10 VAR=.4342944*ALOG(AMAX1(1.,VAR))
 0006           11 DO 4 N=1,K                                                            1050
 0007              IF (VAR - TABLE(N,1)) 3, 2, 4                                         1060
 0008            2 CUT=TABLE(N,2)                                                        1070
 0009              GO TO 99                                                              1080
 0010            3 IF (N-1) 5, 5, 6                                                      1090
 0011            6 CUT= TABLE(N-1,2) + ((TABLE(N,2)- TABLE(N-1,2))*(VAR- TABLE(N-1,1))1100
                  1)/(TABLE(N,1)- TABLE(N-1,1)))                                         1110
 0012              GO TO 99                                                              1120
 0013            4 CONTINUE                                                              1130
 0014              CUT= TABLE(K,2)                                                       1140
 0015              GO TO 7                                                               1150
 0016            5 CUT= TABLE(1,2)                                                       1160
 0017            7 PRINT 100, VAR, NC                                                    1170
 0018           99 IF(LCUT)12,13,12
 0019           12 KK=CUT
 0020              CUT1=KK
 0021              CUT2=ABS(CUT-CUT1)
 0022              CUT = (10.**CUT1) * (10.**CUT2)                                       1176
 0023           13 RETURN                                                                1177
 0024          100 FORMAT (1H1, 10HARGUMENT  , F11.4, 25H OUTSIDE BOUNDARIES OF TABLE1080
                  1 , I2)                                                                1085
 0025              END                                                                   1050
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FORTRAN IV G LEVEL  20              MCAFY            DATE = 71356        12/55/56            PAGE 0001

 0001                 SUBROUTINE MCAFY( A, B, C, X, D, E, F, H, I, J, K, L, M)        1010
                C     THIS SUBR MODIFIES COST ITEMS TO ALLOW FOR INTEREST, O+C,ETC.   1020
 0002                 REAL K,L,M,I,J
 0003                 COMMON/C/ ENR, CRF, XC, XP                                      1025
 0004                 N=A+.5
 0005                 A=N
 0006                 N=.1*(A+B)+.5
 0007                 C=N
 0008                 N=.1*(A+B+C)+.5
 0009                 D=N
 0010                 N=.01625*(A+B+C+D)+.5
 0011                 E=N
 0012                 F = A + B + C + D + E                                           1070
 0013                 N=F+.5
 0014                 G=N
 0015                 N=X*F+.5
 0016                 H=N
 0017                 N=F*CRF+.5
 0018                 I=N
 0019                 N=.007*(G+H+I)+.5
 0020                 J=N
 0021                 K = G + H + I + J                                               1110
 0022                 N =(K / (XC * .365)) * 10000. + .5                              1120
 0023                 L = N/10000.                                                    1130
 0024                 N =(K / (XP * .365)) * 10000. + .5                              1140
 0025                 M = N/10000.                                                    1150
 0026                 RETURN                                                          1140
 0027                 END
```

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FORTRAN IV G LEVEL  20                 BLK DATA          DATE = 71356         12/55/56               PAGE 0001

0001               BLOCK DATA
0002               COMMON/ TABLE/ TT1(10,2), TT2(11,2),TT3A(19,2), TT3B(13,2),          070
                 1     TT3C(13,2), TT3D(14,2), TT3E(11,2), TT3F(15,2), TT4(4,2),       080
                 2     TT5J(20,2), TT5N(23,2), TT6(7,2), TT7(13,2), TT8(6,2),          090
                 3     TT9(18,2), TT10(12,2), TT11(8,2)                                110
             C     LIST PERMANENT DATA TABLES                                          1234
             C     TABLE I   REYNOLDS NO. VS FRICTION FACTOR                           1135
0003               DATA TT1/ 3.301,3.655,4.0,4.655,5.0,5.655,6.0,6.301,6.699,7.0,     11400080
                 1  -2.152,-2.083,-3.982,-3.815,-3.748,-3.643,-3.602,-3.568,-3.505, 11500080
                 2  -3.471/
             C     TABLE II   INSIDE PIPE DIAMETER VS APPROXIMATE YIELD PRESSURE -J55 1165
0004               DATA TT2 / 3.,3.5,4.,5.,6.,8.,10.,12.,16.,18.,20.,                 11700080
                 1     3150.,2775.,2550.,2255.,2100.,1860.,1650.,1470.,1200.,1080.,  11750080
                 2     535./
             C     TABLE IIIA  DEPTH VS DRILLING COST PER FOOT FOR ARC DIST. 6
0005               DATA TT3A/ 800.,1100.,1750.,2300.,3000.,3800.,4300.,4700.,5300.,  11500080
                 1  6000.,                                                             11550080
                 1  6500.,7000.,7800.,8600.,9400.,10000.,10500.,14600.,15000., 8.,  12000080
                 2 8.,8.,8.1,9.9,10.,10.5,11.1,12.,13.5,14.4,15.5,17.4,19.5,
                 3  22.3,24.3,26.5,36.5,50.3/
             C     TABLE IIIB  DEPTH VS DRILLING COST PER FOOT FOR ARC DIST. 3
0006               DATA TT3B/ 700.,1850.,2400.,2950.,3500.,4150.,4750.,5550.,6350.,  12300080
                 1  7550.,11800.,14000.,15000.,16.4,12.4,12.0,11.6,11.6,10.5,10.,
                 2  10.,11.,12.3,23.4,34.5,58.4/
             C     TABLE IIIC  DEPTH VS DRILLING COST PER FOOT FOR ARC DIST. 4
0007               DATA TT3C/ 700.,1700.,4000.,5000.,6000.,7200.,8000.,9000.,10000., 12600080
                 1  10600.,11000.,12000.,15000.,6.7,6.2,6.3,6.4,5.5,8.,13.6,18.3,
                 2  17.,14.8,14.4,18.5,22.3/
             C     TABLE IIID  DEPTH VS DRILLING COST PER FOOT FOR ARC DIST. 5
0008               DATA TT3D/ 700.,1200.,1600.,2100.,2600.,3000.,3500.,4500.,5950.,  12900080
                 1  7400.,8750.,10000.,13800.,15000.,15.2,15.2,15.1,15.6,20.4,21.,
                 2  20.4,17.7,18.3,21.2,24.5,26.9,47.5,68./
             C     TABLE IIIE  DEPTH VS DRILLING COST PER FOOT FOR ARC DIST. 1
0009               DATA TT3E/ 800.,1800.,3200.,4250.,5200.,6500.,7500.,8850.,10000., 13200080
                 1  13700.,15000.,6.8,6.9,7.4,7.7,8.,8.4,9.2,11.4,13.3,26.5,37.3/
             C     TABLE IIIF  DEPTH VS DRILLING COST PER FOOT FOR ARC DIST. 2
0010               DATA TT3F/ 200.,600.,1000.,1500.,2000.,3000.,5000.,7000.,7700.,   13320080
                 1  8500.,9000.,9500.,12500.,13500.,15000.,15.6,15.5,15.3,14.7,
                 2   13.6,11.6,12.3,14.3,15.,15.6,16.,16.3,20.,23.6,21.2/
             C     TABLE IV  DEPTH VS INJECTIVITY COST                                13350080
0011               DATA TT4/0.,5000.,6000.,16000.,1000.,1000.,1020.,2020./
             C     TABLE VI  INSIDE DIAMETER VS COST PER FOOT  J-55                  13450080
0012               DATA TT5J/ 0.,0.5,1.,1.5,2.,2.5,3.,3.6,4.9,6.1,7.1,8.0,9.8,11.5,  13500080
                 1     13.2,15.6,17.,18.,19.,20.,                                      13600080
                 2             0.,.2,.4,.56,.75,.9,1.05,1.26,1.8,2.3,2.85,3.35,4.4,   13700080
                 3     5.45,6.48,8.05,8.68,9.93,10.67,11.5/
             C     TABLE VA  INSIDE DIAMETER VS COST PER FOOT  N-80                  14050080
0013               DATA TT5N/ 0.,0.5,1.,1.5,2.,2.5,3.,3.6,4.5,5.7,6.2,7.,7.7,8.4,9.7,14100080
                 1     10.9,12.1,13.3,14.4,17.,18.,19.,20.,                            14150080
                 2             0.,.35,.60,.84,1.02,1.23,1.45,1.7,2.38,2.64,3.16,3.72, 14200080
                 3     4.33,4.88,6.,7.13,8.25,9.38,10.51,13.1,14.25,15.3,16.3/
             C     TABLE VI OUTSIDE DIAMETER VS CEMENT LINING COST PER FOOT          14250080
0014               DATA TT6/ 0.,8.7,12.6,13.,18.,19.,20.,                             14400080
```

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                    1          0.,1.6,2.5,2.6,3.6,3.8,4.0/
                C       TABLE VII  BRAKE HORSEPOWER VS COST OF PUMP & MOTOR PER HP        14450080
 0015 -                 DATA TT7/ 0.,1.,1.301,1.699,2.,2.301,2.477,2.845,3.,3.301,3.477,  14500080
                    1          3.699,4.,                                                  14540080
                    2      3.114,2.76,2.176,1.954,1.813,1.699,1.672,1.623,1.515,1.301,  14560080
                    3          1.176,1.,0.778/
                C       TABLE VIII RAW WATER STORAGE VS CONSTRUCTION COST                 14650080
 0016                   DATA TT8/0.,500000.,1000000.,2000000.,5000000.,10000000.,13000.,  1470  80
                    1    13300.,20000.,30000.,50000.,80000./
                C       TABLE IX  FLOW RATE VS OPERATION & MAINTENACE COST                14850080
 0017                   DATA TT9/180000.,100000.,200000.,300000.,600000.,1000000.,
                   11500000.,2500000.,3500000.,4000000.,5000000.,6000000.,8000000.,
                    2  10000000.,20000000.,30000000.,40000000.,50000000.,
                    3  1000.,1825.,2715.,3860.,5475.,7300.,9710.,12550.,15570.,18260., 15100080
                    4  21500.,25750.,33300.,40150.,65700.,87550.,110600.,127750./
                C       TABLE X  LOG FLOW VS LOG OPERATION COST                           15150080
 0018                   DATA TT10/ 3.,3.301,3.602,4.,4.301,4.602,4.699,4.845,5.,6.301,7., 15300080
                    1    8.,                                                              15350080
                    2              3.1,3.13,3.184,3.286,3.38,3.518,3.544,3.613,3.711,4.67,15400080
                    3    5.164,5.504/
                C       TABLE XI    PIPE DIA., 300 PSI INCHES, VS. COST, $/FOOT           15700080
 0019                   DATA TT11/ 0.,10.,12.,24.,33.,36.,35.,60.,                        15800080
                    1          0.,4.45,5.66,7.42,20.51,23.30,26.18,52.07/
 0020                   END
```

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FORTRAN IV G LEVEL  20                EVAP              DATE = 71356        12/35/56              PAGE 0001

 0001                SUBROUTINE EVAP
               C
               C   **********************************************************************
               C   *                                                                    *
               C   *                              MAINBE                                *
               C   *      BRINE DISPOSAL BY EVAPORATION MAIN PROGRAM                    *
               C   *                                                                    *
               C   **********************************************************************
               C
 0002                IMPLICIT REAL*8(A-H,O-Z)
 0003                REAL*8 KW
 0004                DIMENSION ANAME(10)
               C
               C     XC       BRINE FLOW
               C     XW       PRODUCT FLOW CAPACITY
               C     CE       BRINE CONCENTRATION
               C     PREC     PRECIPITATION
               C     EC       EVAPORATION RATE
               C     FF       DISTANCE FROM PLANT TO SOURCE
               C     EL       ELEVATION OF SOURCE
               C     ECU      POWER COST
               C     CLU      LAND COST
               C     ZI       CAPITAL DISCOUNT RATE
               C     Y        PROJECT LIFE
               C     BCI      BUILDING COST INDEX
 0005                AMORT(X,Z)=(X*(1.+X)**Z)/((1.+X)**Z-1.)
 0006           995  READ 51, (ANAME(J),J=1,10),XC,XW,CE,PREC,EC,FF,EL,ECU,CLU,ZI,Y,BCI
                    1,XLAST
 0007             51 FORMAT(10A8/8F10.3/4F10.3,F10.0)
 0008                XW=XW*1.D6
 0009                XC=XC*1.D6
 0010                ZI=ZI/100.
 0011                IPRNT=6
 0012                LIST=6
 0013                COMT=0.
 0014                TICST=0.
 0015                RWY=0.
 0016                AFF=0.
 0017                XIC=0.
 0018                DUM1=0.D0
 0019                DUM2=0.D0
 0020                DUM3=0.D0
 0021                DUM4=0.D0
 0022                FC=0.D0
               C     PRELIM CALCS FOR DIKE COSTS
 0023                FN=FC-PREC
 0024                IF(FN.GT.0.D0) GO TO 8000
 0025                 WRITE(6,6)
 0026            6    FORMAT('0 *** ERROR -- ZERO NET PRECIPITATION')
 0027                GO TO 100
 0028          8000  XCD=XC/1000.
 0029                AF=13.44*XCD/FN
 0030                BA=4.2*(((CE-50000.)/50000.)*4.2)
```

```
      H=8.*RA
C      CORE MATERIAL VOLUME
      IF (AF-135.) 8001,8001,8002
 8001 XL=(.0154*AF)+.6
      GO TO 8003
 8002 XL=(.0066*AF)+2.85
 8003 IF (H-6.) 11,11,12
   11 WL=2.25*H-2.
      GO TO 13
   12 WL=5.74*H-22.54
   13 VT=XL*WL
      AT=(((.02*AF)*(RA+2.))/10.)*((.02*AF)
      AL=((((.01111*AF)+6.)*(RA+2.))/10.)*((.01111*AF)
      VF=((((35.*AF)+15000.)*(RA+3.))/10.)*((16.25*AF)+5000.
      CI=((XC**.45)*.0171)+.5
      CC=(1.055*CI)+.2226
   16 IF (CI-5.5) 17,17,18
   17 PWNAC=3.84*CI-1.15
      GO TO 22
   18 PWNAC=7.57*CI-21.62
   22 VENAC=104.5*CI+1068.
      F=5280.*FF
      CPU=.109*PWNAC+.506
      HF=.0038*F
      DH=EL-HF
   10 IF (DH) 8,9,9
    8 DH=-DH
      DPD=.434*DH
      HHP=(XC*DPD)/ 246000.
      BHP=HHP/.88
      KW=BHP*.8
      CFM=XC/1440.
   55 PCU=10.**(3.-(.525*ALOG10(PWR)))      1
      PC=PCU*BHP
      STR=PC
      GO TO 53
    9 STR=0.0
      KW=0
   53 CL=CLL*AT
      CS=AT*100.
      CLL=AL*.031
      CF=VF*.40
      CE=VT*1.00
   84 ST1=CL+CS+CLL+CF+CE
      TICST=TICST+CL
      ST1R=CS+CLL+CF+CE
      CCU=CE*.2
      CP=F*CPU
      CC=F*CCL
      STA=((CP+CC)*PC1)/570.
      CI=F*.60
      CR=F*.075
   85 ST2=STA+CI+CR
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 0083                 ST2R=CP+CC+CI
 0084                  RWY=RWY+CR
                C     ROAD COSTS
 0085                 CTC=ST1*.10
 0086                 CCNT=CCNT+CTC
 0087                 ENG=.10*(ST1+CTC)
 0088                 AEE=AEE+ENG
 0089                 XNT=.01625*(ST1+CTC+ENG)
 0090                 XIC=XIC+XNT
 0091              80 CC1=ST1+CTC+ENG+XNT
 0092                 A1=CC1*AMORT(ZI,Y)
 0093                 DUM1=CC1*.005
 0094                 DUM2=DUM1*.15
 0095                 DUM3=.30*(DUM1+DUM2)
 0096                 DUM4=.007*(A1+DUM1+DUM2+DUM3)
 0097              81 AC1=A1+DUM1+DUM2+DUM3+DUM4
                C    PIPE COSTS
 0098                 DUM1=ST2*.10
 0099                 DUM2=.10*(ST2+DUM1)
 0100                 DUM3=.01625*(ST2+DUM1+DUM2)
 0101              82 CC2=ST2+DUM1+DUM2+DUM3
 0102                 A2=CC2*AMORT(ZI,Y)
 0103                 DUM1=.0025*CC2
 0104                 DUM2=.007*(A2+DUM1)
 0105              83 AC2=A2+DUM1+DUM2
                C    PUMP STATION COSTS
 0106                 IF (STR) 24,24,25
 0107            24   CONTINUE
 0108                 GO TO 27
 0109              25 DUM1=.10*STR
 0110                 DUM2=.10*(STR+DUM1)
 0111                 DUM3=.01625*(STR+DUM1+DUM2)
 0112                 CC3=STR+DUM1+DUM2+DUM3
 0113                 A3=CC3*AMORT(ZI,Y)
 0114                 DUM1=.0025*CC3
 0115                 PC=KW*PCL*8760.
 0116                 GO TO 300
 0117              27 CC3=0.
 0118                 A3=0.
                C     O+M CALCS
 0119             300 IF (XC.GT.1000..AND.XC.LT.10.999) GO TO 58
 0120                 WRITE (IPRNT,50) XC
 0121              50 FORMAT ('X10) OUTSIDE RANGE, X(C)=', F10.1)
 0122                 GO TO 100
 0123              58 OEM=10.**(.0251+.645*(ALOG10(XC)))
 0124                 DUM2=OEM*.15
 0125                 DUM3=(OEM+DUM2)*.3
 0126                 DUM4=.007*(A3+DUM1+DUM2+DUM3 +PC+OEM)
 0127                 AC3=A3+DUM1+DUM2+DUM3+DUM4+OEM+PC
                C
 0128                 TREND=PCI/520.
 0129                 TRST1=ST1*TREND
 0130                 TRST2=ST2*TREND
```

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FORTRAN IV G LEVEL  21                MAIN              DATE = [illegible]        [illegible]              PAGE 0004

 0131              TRSTR=STR*TREND
 0132              COST1=ST1R+ST2R+STR
 0133              COST2=COST1*TREND
 0134              COSTTT=COST2+AFF+RWY+CCAT+XIC+TLCST
 0135        1001  CONTINUE
 0136              COSTAE=AC1+AC2+AC3
 0137              COST3=COSTAE/(XLF*.365)
 0138              COST4=COSTAE*1.E-6
 0139              COST5=COSTAE/(XMW*.365)
 0140              COST6=COSTTT*1.E-6
 0141              XL=XL/1.E6
 0142              XW=XW/1.E6
 0143              ZI=ZI*100.
            C
            C   **** SUMMARY OF MODEL DATA
 0144              WRITE(LIST,2000)           (   ANAME(J),J=1,10)
 0145              WRITE( LIST,2001) XC          ,COST59,COST3,COST4,COST6
 0146              WRITE(LIST,5) XC,XW,CE,PREC,EC,EF,EL,ECL,CIL,ZI,ECI,Y
            C
            C     **** COST FOR MODEL
            C
 0147              WRITE(LIST,2000)                (ANAME(J),J=1,10)
 0148              WRITE(LIST,2001) ST1R,TREND,TRST1
 0149              WRITE(LIST,2002) ST2R,TREND,TRST2
 0150              WRITE(LIST,2003) STR,TREND,TRSTR
 0151              WRITE(LIST,2003) COST1,COST2
            C
            C     *** FAC. COST
            C
 0152              WRITE(LIST,2050)
 0153              WRITE(LIST,2051) AFF
 0154              WRITE(LIST,2052) TLCST
 0155              WRITE(LIST,2053)RWY
 0156              WRITE(LIST,2054) CCAT
 0157              WRITE(LIST,2055) XIC
 0158              WRITE(LIST,2056) COSTTT
 0159              WRITE(LIST,2100)
 0160              WRITE(LIST,2101)AC1
 0161              WRITE(LIST,2102)AC2
 0162              WRITE(LIST,2103)AC3
 0163              WRITE(LIST,2104)COSTAE
 0164        5     FORMAT (/////'      I SUMMARY OF MODEL DATA'//
                  15X,'CAPACITIES'//14X,'BRINE FLOW      ',40X,F10.3,' MGPD'/
                  214X,'RECYCLE FLOW    ',41X,F10.3,' MGPD'///
                  214X,'BRINE CONCENTRATION',37X,F10.0,'PPM'///
                  214X,'PRECIPITATION        ',37X,F10.0,' IN '///
                  214X,'EVAPORATION RATE    ',37X,F10.0,' IN '///
                  35X,'DISCHARGE FIELD'//14X,'DISTANCE FROM POINT TO DISCHARGE STATIO
                  XN',16X,F10.2,' MILES'//14X,'ELEVATION OF DISCHARGE STATION FROM POI
                  XNT',15X,F10.2,' FEET'///
                  45X,'RATES'//14X,'POWER COST',46X,F10.4,' $/KWH'/14X,'LAND COST',
                  X47X,F10.0,' $/ACRE'/14X,'CAPITAL DISCOUNT RATE',35X,F10.3,' PERCEN
                  XT'/14X,'BUILDING COST INDEX',37X,F10.0/14X,'PROJECT LIFE',44X,
FORTRAN IV G LEVEL  20                EVAP             DATE = 71356        12/59/56             PAGE 0005

                   XF10.0,' YEARS')
 0165         2000 FORMAT('1', '  COST ESTIMATES FOR BRINE DISPOSAL BY EVAPORATION'
                  1,              //20X,1CAP///'   II  CONSTRUCTION COSTS'/
                  224X,'CONSTRUCTION COST'/40X,'CONSTRUCTION COST    TREND         ',
                  2'TRENDED TO'/10X,'FACILITY',22X,'BEFORE TRENDING      FACTOR',
                  37X,'CURRENT YEAR'/10X,'---------',22X,'-----------------',
                  4'     ------',7X'-----------------'/ )
 0166         2001 FORMAT(5X,'EVAPORATION POND                     $',F11.0,10X,F5.2,
                  18X,'$',F11.0)
 0167         2002 FORMAT(5X,'TRANSMISSION PIPE LINE               $',F11.0,10X,F5.2,
                  18X,'$',F11.0)
 0168         2003 FORMAT(5X,'PIPE LINE PUMPING STATIONS           $',F11.0,10X,F5.2,
                  18X,'$',F11.0)
 0169         2007 FORMAT(/5X,'TOTAL                               $',F11.0,15X,
                  18X,'$',F11.0//, )
 0170         2050 FORMAT(2X,'III  CAPITAL INVESTMENT '//)
 0171         2051 FORMAT(5X,'ENGINEERING, ADMINISTRATION AND FINANCING', 20X,
                  18X,'$',F11.0)
 0172         2052 FORMAT(5X,'TOTAL LAND COST                                 ', 20X,
                  18X,'$',F11.0)
 0173         2053 FORMAT(5X,'RIGHTS OF WAY                                   ', 20X,
                  18X,'$',F11.0)
 0174         2054 FORMAT(5X,'CONTINGENCIES                                   ', 20X,
                  18X,'$',F11.0)
 0175         2055 FORMAT(5X,'INTEREST DURING CONSTRUCTION                    ', 20X,
                  18X,'$',F11.0)
 0176         2056 FORMAT(/5X,'TOTAL                                     ',26X,
                  18X,'$',F11.0/// )
 0177         2100 FORMAT(            3X,'IV   ANNUAL EXPENDITURES'//
                  110X,'FACILITY',56X,'COST'/10X,'---------',56X,'----'/)
 0178         2101 FORMAT(5X,'EVAPORATION POND                     ',26X,
                  18X,'$',F11.0)
 0179         2102 FORMAT(5X,'TRANSMISSION PIPE LINE               ',26X,
                  18X,'$',F11.0)
 0180         2103 FORMAT(5X,'PIPE LINE PUMPING STATION            ',26X,
                  18X,'$',F11.0)
 0181         2104 FORMAT(///5X,'TOTAL                                 ',26X,
                  18X,'$',F11.0)
 0182         3000 FORMAT('1'//'  COST ESTIMATES FOR BRINE DISPOSAL BY EVAPORATION'
                  1,              //                   20X,1CAP///)
 0183         3001 FORMAT( ' QUANTITY OF EFFLUENT                         MG',17X,
                  A' ',F11.3,
                  A         '0COST PER THOUSAND GALLONS OF PRODUCT PETRO ',17X,
                  A'$',F11.3/
                  1'0COST PER THOUSAND GALLONS OF EFFLUENT                ',10X,
                  A'$',F11.3/
                  1'0ANNUAL EXPENDITURES -- MILLION  OF DOLLARS        ',5X,' $',
                  AF11.3/'0CAPITAL INVESTMENT -- MILLION  OF DOLLARS',15X,'$',F11.3/)
 0184          100  IF(KLAST.EQ.1.) GO TO 597
 0185               GO TO 595
 0186          597  RETURN
 0187               END
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FORTRAN IV G LEVEL  21              CONVEY           DATE = 71356        12/55/56              PAGE 0001
 0001              SUBROUTINE CONVEY
                C
                C   *********************************************************************0100
                C   *                                                                   *0200
                C   *                            MAINBC                                 *0300
                C   *       BRINE DISPOSAL BY CONVEYANCE MAIN PROGRAM                   *0400
                C   *                                                                   *0500
                C   *********************************************************************0600
                C                                                                        0700
 0002               IMPLICIT REAL*8(A-H,O-Z)                                             0800
 0003               REAL*8 KW                                                            1300
 0004               DIMENSION ANAME(10)                                                  1400
                C     XC       BRINE FLOW
                C     XW       PRODUCT FLOW CAPACITY                                     3900
                C     DD       DISTANCE FROM PLANT TO SOURCE                             4000
                C     EL       ELEVATION OF SOURCE                                       4100
                C     PCL      POWER COST                                                4200
                C     ZI       CAPITAL DISCOUNT RATE                                     4300
                C     BCI      BUILDING COST INDEX                                       4400
                C     Y        PROJECT LIFE                                              4500
 0005               AMORT(X,Z)=(X*(1.+X)**Z)/((1.+X)**Z-1.)                              4600
 0006           999 READ 51, (ANAME(J),J=1,10),XC,XW,PCL,BCI,DD,EL,Y,ZI,XLAST            3600
 0007            51 FORMAT(10A8/2F10.2,F10.3,4F10.2,F10.4/F10.0)
 0008               IPRNT=6
 0009               LIST=6
 0010               XW=XW*1.D6
 0011               XC=XC*1.D6
 0012               ZI=ZI/100.
 0013               EC=0.D0
 0014               DI=((XC**.45)*.017)*.5                                               4800
 0015               OD=(1.055*DI)+.2225                                                  4900
 0016            16 IF (DI-5.5) 17,17,18                                                 5000
 0017            17 PWNPC=3.64*DI-1.15                                                   5100
 0018               GO TO 22                                                             5200
 0019            18 PWNPC=7.57*DI-21.62                                                  5300
 0020            22 YPNPC=104.5*DI+3068                                                  5400
 0021               F=5280.*DD                                                           5500
 0022               CPU=.109*PWNPC+.506                                                  5600
 0023               HF=.003*F                                                            5700
 0024               DH=EL-HF                                                             5800
 0025            30 IF (DH) 5,9,9                                                        5900
 0026             5 DH=-DH                                                               6000
 0027               FCP=.434*DH                                                          6100
 0028               HHP=(XC*FCP)/ 2468000.                                               6200
 0029               BHP=HHP/.85                                                          6300
 0030               KW=BHP*.9                                                            6400
 0031               GPM=XC/1440.                                                         6500
 0032               PCU=10.**(3.-(.525*DLOG10(BHP))      )                               6600
 0033               PC=PCL*BHP                                                           6700
 0034               STR=PC                                                               6800
 0035               GO TO 12                                                             6900
 0036             9 STR=0.0                                                              7000
                C       SUPPLY PIPE COST                                                 7100
                                                                                         7200
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FORTRAN IV G LEVEL  20                CONVEY           DATE = 71356        12/35/58              PAGE 0002

 0037           12 CP=F*CPL                                                          7300
 0038              CPU=CP*.2                                                         7400
 0039              CC=F*CCL                                                          7500
 0040              STA=((CP+CC)*PCT)/570.                                            7600
 0041              CT=F*.60                                                          7700
 0042              CR=F*.025                                                         7800
 0043              ST2=STA+CT+CR                                                     7900
 0044              ST2R=CP+CC+CT                                                     8000
 0045              RWY=CR                                                            8100
 0046              DUM1=ST2*.10                                                      8200
 0047              AFF=DUM1                                                          8300
 0048              DUM2=.10*(ST2+DUM1)                                               8400
 0049              CONT=DUM2                                                         8500
 0050              DUM3=.01625*(ST2+DUM1+DUM2)                                       8600
 0051              XIC=DUM3                                                          8700
 0052              CC2=ST2+DUM1+DUM2+DUM3                                            8800
 0053              A2=CC2*ANCRT(IT,Y)                                                8900
 0054              DUM1=.0025*CC2                                                    9000
 0055              DUM2=.007*(A2+DUM1)                                               9100
 0056              AC2=A2+DUM1+DUM2                                                  9200
             C    PUMP STATION COSTS                                                 9300
 0057              IF (STP) 24,24,25                                                 9400
 0058          24   CONTINUE                                                         9500
 0059              CC3=0.                                                            9600
 0060              A3=0.                                                             9700
 0061              GO TO 99                                                          9800
 0062           25 DUM1=.10*STP                                                      9900
 0063              DUM2=.10*(STP+DUM1)                                               A100
 0064              DUM3=.01625*(STP+DUM1+DUM2)                                       A101
 0065              CC3=STP+DUM1+DUM2+DUM3                                            A102
 0066              A3=CC3*ANCRT(IT,Y)                                                A103
 0067              DUM1=.0025*CC3                                                    A104
 0068              PC=KW*ECL*8760.                                                   A105
 0069           27 CONTINUE                                                          A106
             C     O&M CALCS                                                         A107
 0070              IF (XC.GE.1000..AND.XC.LE.10.**5) GO TO 58                        A108
 0071              WRITE (IPRNT,50) XC                                               A109
 0072           50 FORMAT (' X(C) OUTSIDE RANGE, X(C)=', F10.1)                      A110
 0073              GO TO 100                                                         A111
 0074           58 OEM=10.**(.0291+.645*(ALOG10(XC)))                                A112
 0075              DUM2=OEM*.15                                                      A113
 0076              DUM3=(OEM+DUM2)*.3                                                A114
 0077              DUM4=.007*(A3+DUM1+DUM2+DUM3 +PC+OEM)                             A115
 0078              AC3=A3+DUM1+DUM2+DUM3+DUM4+OEM+PC                                 A116
             C      TOTALS                                                           A117
             C                                                                       0100
             C   ******************************************************************0200
             C   *                                                                 *0300
             C   *      PRIME DISPOSAL BY CONVEYANCE PRINT PROGRAM                 *0500
             C   *                                                                 *0600
             C   ******************************************************************0700
             C                                                                       0800
 0079           99  CONTINUE
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FORTRAN IV G LEVEL  20              CONVEY            DATE = 71356        12/55/56              PAGE 0003

 0080                TREAT=PCI/570.                                                               4300
 0081                TRST2=ST2R*TREAT                                                             4400
 0082                TRSTR=STR*TREAT                                                              4500
 0083                ST1R=0.D0                                                                    4600
 0084                AC1=0.D0                                                                     4700
 0085                TLCST=0.D0                                                                   4800
 0086                COST1=ST1R+ST2R+STR                                                          4900
 0087                COST2=COST1*TREAT                                                            5000
 0088                COSTTT=COST2+AFF+RWY+CONT+XIC+TLCST                                          5100
 0089                COSTAF=AC1+AC2+AC3                                                           5200
 0090                COST99=COSTAF/(XW*.365)                                                      5300
 0091                COST3=COSTAF/(XC*.365)                                                       5400
 0092                COST4=COSTAF*1.D-6                                                           5500
 0093                COST5=COSTTT*1.D-6                                                           5600
 0094                XC=XC/1.D6
 0095                XW=XW/1.D6
 0096                ZI=ZI*100.
               C                                                                                  5900
               C  **** SUMMARY OF MODEL DATA                                                      6000
               C                                                                                  6100
 0097                WRITE(LIST,3000)              (ANAME(J),J=1,10)
 0098                WRITE( LIST,3001) XC          ,COST99,COST3,COST4,COST5                      6400
 0099                WRITE(LIST,5) XC,XW,EE,EL,ECL,ZI, RCI,Y
               C                                                                                  6800
               C    **** COST FOR MODEL1                                                          6900
               C                                                                                  7000
 0100                WRITE(LIST,2000)              (ANAME(J),J=1,10)
 0101                WRITE(LIST,2002) ST2R,TREAT,TRST2                                            7300
 0102                WRITE(LIST,2003) STR,TREAT,TRSTR                                             7400
 0103                WRITE(LIST,2007) COST1,COST2                                                 7500
               C                                                                                  7600
               C    *** ENG. COST                                                                 7700
               C                                                                                  7800
 0104                WRITE(LIST,2050)                                                             7900
 0105                WRITE(LIST,2051) AFF                                                         8000
 0106                WRITE(LIST,2053)RWY                                                          8100
 0107                WRITE(LIST,2054) CONT                                                        8200
 0108                WRITE(LIST,2055) XIC                                                         8300
 0109                WRITE(LIST,2056) COSTTT                                                      8400
 0110                WRITE(LIST,2100)                                                             8500
 0111                WRITE(LIST,2102)AC2                                                          8600
 0112                WRITE(LIST,2103)AC3                                                          8700
 0113                WRITE(LIST,2104)COSTAF                                                       8800
 0114           5    FORMAT (/////'     I  SUMMARY OF MODEL DATA'//                               9100
                    15X,'CAPACITIES'//14X,'BRINE FLOW      ',40X,F10.2,' MGPD'/                  9200
                    214X,'PRODUCT FLOW   ',41X,F10.2,' MGPD'///                                   9300
                    35X,'DISCHARGE FIELD'//14X,'DISTANCE FROM POINT TO DISCHARGE STATIO9400
                    XN',16X,F10.2,' MILES'/14X,'ELEVATION OF DISCHARGE STATION FROM PO9500
                    XINT',15X,F10.2,' FEET'///                                                    9600
                    45X,'RATES'//14X,'POWER COST',46X,F10.4,' $/KWH'/                             9700
                    X                         14X,'CAPITAL DISCOUNT RATE',35X,F10.3,' PERCEN9800
                    XT'/14X,'BUILDING COST INDEX',37X,F10.0/14X,'PROJECT LIFE',44X,         9900
                    XF10.0,' YEARS')                                                              X100
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FORTRAN IV G LEVEL  20                CONVEY              DATE = 71356         12/55/56                PAGE 0004

 0115        2000 FORMAT('1', '  COST ESTIMATES FOR BRINE DISPOSAL BY CONVEYANCE '  X101
                 1,              //20X,ICAR///'   II  CONSTRUCTION COSTS'/          X102
                 274X,'CONSTRUCTION COST'/40X,'CONSTRUCTION COST    TREND       ', X103
                 2'TRENDED TO'/10X,'FACILITY',22X,'BEFORE TRENDING      FACTOR',    X104
                 37X,'CURRENT YEAR'/10X,'---------',22X,'-----------------',        X105
                 4'     ------',7X,'----------------'/ )                            X106
 0116        2002 FORMAT(5X,'TRANSMISSION PIPE LINE            $',F11.0,10X,F5.2,   X107
                 18X,'$',F11.0)                                                     X108
 0117        2003 FORMAT(5X,'PIPE LINE PUMPING STATIONS        $',F11.0,10X,F5.2,   X109
                 18X,'$',F11.0)                                                     X110
 0118        2007 FORMAT(/5X,'TOTAL                             $',F11.0,19X,       X111
                 18X,'$',F11.0/// )                                                 X112
 0119        2050 FORMAT(2X,'III  CAPITAL INVESTMENT '//)                           X113
 0120        2051 FORMAT(5X,'ENGINEERING, ADMINISTRATION AND FINANCING', 20X,       X114
                 18X,'$',F11.0)                                                     X115
 0121        2053 FORMAT(5X,'RIGHTS OF WAY                              ', 20X,     X116
                 18X,'$',F11.0)                                                     X117
 0122        2054 FORMAT(5X,'CONTINGENCIES                              ', 20X,     X118
                 18X,'$',F11.0)                                                     X119
 0123        2055 FORMAT(5X,'INTEREST DURING CONSTRUCTION               ', 20X,     X120
                 18X,'$',F11.0)                                                     X121
 0124        2056 FORMAT(/5X,'TOTAL                              ',26X,             X122
                 18X,'$',F11.0/// )                                                 X123
 0125        2100 FORMAT(            3X,'IV   ANNUAL EXPENDITURES'//                X124
                 110X,'FACILITY',56X,'COST'/10X,'---------',58X,'----'/)            X125
 0126        2102 FORMAT(5X,'TRANSMISSION PIPE LINE             ',26X,              X126
                 18X,'$',F11.0)                                                     X127
 0127        2103 FORMAT(5X,'PIPE LINE PUMPING STATION          ',26X,              X128
                 18X,'$',F11.0)                                                     X129
 0128        2104 FORMAT(///5X,'TOTAL                               ',26X,          X130
                 18X,'$',F11.0)                                                     X131
 0129        3003 FORMAT('1'//'  COST ESTIMATES FOR BRINE DISPOSAL BY CONVEYANCE '  X132
                 1,            //                    20X,ICAR///)                   X133
 0130        3001 FORMAT( '0QUANTITY OF EFFLUENT                       MG',17X,     X134
                 A' ',F11.3/                                                        X135
                 A          '0COST PER THOUSAND GALLONS OF PRODUCT WATER ',17X,     X136
                 A'$',F11.3/                                                        X137
                 1'0COST PER THOUSAND GALLONS OF EFFLUENT               ',10X,      X138
                 A'$',F11.3/                                                        X139
                 1'0ANNUAL EXPENDITURES -- MILLION  OF DOLLARS        ',9X,' $',    X140
                 AF11.3/'0CAPITAL INVESTMENT -- MILLION  OF DOLLARS',15X,'$',F11.3/)X141
 0131        3002 FORMAT(20X,ICAR/)                                                 X142
 0132        100  IF(XLAST.EQ.1.) GO TO 567
 0133             GO TO 895
 0134        567  RETURN
 0135             END                                                               X143
```

```
111

          3.3010          -2.1520
          3.6550          -2.0530
          4.0000          -3.5820
          4.6550          -3.8150
          5.0000          -3.7480
          5.6550          -3.6430
          6.0000          -3.6020
          6.3010          -3.5680
          6.6550          -3.5050
          7.0000          -3.4310

112

          3.0000        3150.0000
          3.5000        2775.0000
          4.0000        2550.0000
          5.0000        2295.0000
          6.0000        2100.0000
          8.0000        1880.0000
         10.0000        1650.0000
         12.0000        1470.0000
         16.0000        1200.0000
         18.0000        1080.0000
         20.0000         575.0000

113A

        900.0000           8.0000
       1100.0000           8.0000
       1750.0000           8.0000
       2300.0000           8.1000
       3000.0000           9.9000
       3800.0000          10.0000
       4300.0000          10.5000
       4700.0000          11.1000
       5300.0000          12.0000
       6300.0000          13.5000
       6500.0000          14.4000
       7000.0000          15.5000
       7800.0000          17.4000
       8600.0000          19.5000
       9400.0000          22.3000
      10000.0000          24.3060
      10500.0000          26.5000
      14600.0000          38.5000
      15300.0000          50.7000
```

```
TT3B

       700.0000          18.4000
      1850.0000          12.4000
      2400.0000          12.0000
      2950.0000          11.8000
      3500.0000          11.4000
      4150.0000          10.5000
      4750.0000          10.0000
      5550.0000          10.0000
      6350.0000          11.0000
      7550.0000          12.3000
     11800.0000          23.4000
     14000.0000          34.5000
     15000.0000          55.4000

TT3C

       700.0000           6.7000
      1700.0000           6.2000
      4000.0000           6.3000
      5000.0000           6.4000
      6300.0000           5.5000
      7200.0000           8.0000
      8300.0000          13.6000
      9000.0000          18.3000
     10300.0000          17.0000
     10600.0000          14.8000
     11100.0000          14.4000
     12300.0000          18.5000
     15000.0000          22.3000

TT3D

       700.0000          15.2000
      1200.0000          15.2000
      1600.0000          15.1000
      2100.0000          15.6000
      2600.0000          20.4000
      3300.0000          21.0000
      3500.0000          20.4000
      4500.0000          17.7000
      5950.0000          18.3000
      7400.0000          21.2000
      8750.0000          24.9000
     10300.0000          26.5000
     13800.0000          47.5000
     15000.0000          68.0000
```

```
TT3B

     800.0000          6.8000
    1900.0000          6.5000
    3300.0000          7.4000
    4300.0000          7.7000
    5300.0000          8.0000
    6500.0000          8.4000
    7500.0000          9.2000
    8500.0000         11.4000
   10000.0000         13.3000
   11300.0000         26.8000
   15000.0000         37.3000

TT3C

     200.0000         15.6000
     600.0000         15.5000
    1100.0000         15.3000
    1500.0000         14.7000
    2200.0000         13.8000
    3300.0000         11.6000
    5200.0000         13.3000
    7000.0000         14.3000
    7700.0000         15.0000
    8500.0000         15.6000
    9000.0000         16.0000
    9500.0000         16.3000
   12500.0000         20.0000
   13500.0000         23.6000
   15300.0000         21.2000

TT4

         0.0        1000.0000
    5100.0000       1000.0000
    6000.0000       1020.0000
   14000.0000       2020.0000
```

```
TTSJ
          0.0             0.0
          0.5000          0.2000
          1.0000          0.4000
          1.5000          0.5600
          2.0000          0.7500
          2.5000          0.9000
          3.0000          1.0500
          3.5000          1.2600
          4.5000          1.8000
          6.1000          2.3000
          7.1000          2.6500
          8.0000          3.7500
          9.5000          4.4000
         11.5000          5.4500
         13.2000          6.4800
         15.6000          8.0500
         17.0000          9.5600
         18.0000          9.9300
         19.0000         10.6700
         20.0000         11.5000

TTSN
          0.0             0.0
          0.5000          0.3800
          1.0000          0.6200
          1.5000          0.8400
          2.0000          1.0200
          2.5000          1.2200
          3.0000          1.4500
          3.6000          1.7000
          4.5000          2.1800
          5.7000          2.8400
          6.2000          3.1600
          7.0000          3.7200
          7.7000          4.3300
          8.4000          4.8800
          9.7000          6.0000
         10.5000          7.1300
         12.1000          8.2800
         13.3000          9.3800
         14.4000         10.5100
         17.0000         13.1000
         18.0000         14.2500
         19.0000         15.3000
         20.0000         16.3000
```

```
116

          0.0                 0.0
          6.2000              1.4000
         12.8000              2.4000
         13.0000              2.8000
         14.0000              3.4000
         15.0000              3.8000
         16.0000              4.0000


117

          0.0                 3.1140
          1.0000              2.3900
          1.3010              2.1780
          1.6990              1.9940
          2.0000              1.9133
          2.3010              1.8550
          2.4770              1.8220
          2.8450              1.6230
          3.0000              1.5150
          3.3010              1.3010
          3.4770              1.1760
          3.8450              1.0000
          4.0000              0.7780


118

          0.0             10000.0000
     500000.0000          13000.0000
    1000000.0000          20000.0000
    2000000.0000          30000.0000
    5000000.0000          40000.0000
   10000000.0000          60000.0000
```

```
TT9
         38700.0000          1000.0000
        100000.0000          1825.0000
        200000.0000          2719.0000
        300000.0000          3560.0000
        600000.0000          5419.0000
       1000000.0000          7300.0000
       1500000.0000          9310.0000
       2500000.0000         12990.0000
       3500000.0000         15970.0000
       4000000.0000         18260.0000
       5000000.0000         21500.0000
       6000000.0000         25750.0000
       8000000.0000         33300.0000
      10000000.0000         40150.0000
      20000000.0000         65700.0000
      30000000.0000         87550.0000
      40000000.0000        110680.0000
      50000000.0000        127750.0000

TT10
            3.0000             3.1000
            3.3010             3.1300
            3.6020             3.1840
            4.0000             3.2860
            4.3010             3.3800
            4.6020             3.5180
            4.6990             3.5440
            4.8450             3.6170
            5.0000             3.7110
            6.3010             4.6700
            7.0000             5.1640
            8.0000             5.5040

TT11
             0.0                0.0
            10.0000             4.4530
            12.0000             5.6600
            14.0000             7.4200
            33.0000            20.5100
            34.0000            23.3000
            35.0000            26.1800
            60.0000            52.0700
```